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Witness:	*Sarah L.K. Lange*
Sponsoring Party:	*MoPSC Staff*
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MISSOURI PUBLIC SERVICE COMMISSION

INDUSTRY ANALYSIS DIVISION

TARIFF/RATE DESIGN DEPARTMENT

REBUTTAL TESTIMONY

OF

SARAH L.K. LANGE

UNION ELECTRIC COMPANY,
d/b/a Ameren Missouri

CASE NO. ER-2019-0335

Jefferson City, Missouri
January 2020

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CASE NO. ER-2019-0335

Q. Please state your name and business address.

A. My name is Sarah L.K. Lange and my business address is Missouri Public Service Commission, P. O. Box 360, Jefferson City, Missouri 65102.

Q. Who is your employer and what is your present position?

A. I am employed by the Missouri Public Service Commission ("Commission") and my title is Regulatory Economist III, Tariff/Rate Design Department of the Commission Staff Division. A copy of my credentials is attached to the Staff's Class Cost of Service Report ("CCOS Report") filed on December 18, 2019, in this matter, to which I contributed. I also provided Supplemental Direct Testimony in this matter concerning rate design.

Q. What is the purpose of your testimony?

A. I will respond to the direct testimonies of Ameren Missouri, MIEC, MECG, and Sierra Club witnesses, as indicated. Broadly, I will address:

a. Clarify the types of "demand," identifying the potential for confusion that was created by certain conflations of the types of demand in various witnesses' direct testimonies,

b. Discuss conceptually Ameren Missouri's customer cost of service study and the push for modernizing rate structures recognized by multiple witnesses,

c. The conceptual approach of Ameren Missouri's direct testimonies in recommending movement towards time-variant rate structures for the residential class, and the parties' testimonies concerning residential time-variant rate designs,

d. Customer bill histories and the impact of rate design on the bills paid by actual customers over time;[1] the parties' testimonies concerning LGS, SPS and LPS rate designs and reliance on the Ameren Missouri CCOS; the cost of obtaining energy to serve load as it relates to proper design of energy charges; and Staff's concerns with Ameren Missouri's CCOS,

e. Other tariff issues raised by Ameren Missouri, including the opt-out ToU rider for non-residential secondary customers, cancelation of the LTS rate schedule, and Ameren Missouri's interest in potential changes to LPS customer qualifications.

DEMAND

Q. Mr. Wills, Mr. Chriss, Mr. Brubaker, and Mr. Allison discuss "demand." What is "Demand?"

A. Even within the context of rate design and class cost of service, the word "demand" has several different meanings. At its most basic, "demand" is simply consumption at a given point in time. In the familiar water analogy, the height of the water in a pipe in an instant is the demand, and the water that drains into the bucket is the energy. In that situation, the higher the water level in the pipe in an instant, the higher the demand. However, as used in energy regulation, "demand" always has a time component. For example, a customer's energy consumption during a specified 15 minute interval, or during a specified one hour interval are the most common meanings of demand.

1. Customer Non-Coincident Peak Demand, or "NCP Demand," is the 15 minute interval during which a particular customer used the most energy during a month or year. Customer NCP Demand may be based on the annual peak usage or monthly peak usage. This is the demand that is measured by a customer's "Demand meter" and is the demand that

[1] I will provide reliable and useful information concerning the effective rates experienced by customers over the last decade in response to misleading information provided by MECG, and provide reliable and useful information concerning the relative contributions of customers to the cost of service over the last decade in response to misleading information provided by MIEC. While neither issue is directly relevant to the Commission's determination in this proceeding, the misleading information that has been provided through prefiled testimony should be clarified.

is subject to an Ameren Missouri "demand charge" on the currently-structured LPS, SPS, and LGS tariffs.

2. Class NCP Demand, is the one hour interval during each month during which a studied rate class comprised of one or more rate schedules used the most energy in the relevant month. Generally, consolidating more than one rate schedule into a studied class will produce a lower total NCP Demand for the consolidated classes than measuring each rate schedule separately and adding them together.

3. Class Coincident Peak Demand is the usage of each studied rate class during the hour at which the system recorded the highest usage during a month or year.

4. System Peak Demand is either the highest energy usage the system experienced during an hour of the year, or the system's load at the time that the relevant RTO experienced its highest energy usage during an hour of the year.

5. Customer Coincident Peak Demand is an emerging billing determinant reflecting the maximum usage of a customer during a specified interval within a specified period, where the specified period encompasses conditions that are associated with system peaks ranging from the local distribution system to the RTO system.

Q. Please explain how a utility utilizes and is impacted by each type of demand.

A.

1. Customer Non-Coincident Peak Demand, or "NCP Demand," (the 15 minute interval during a month or year during which a particular customer used the most energy) is a direct billing determinant for the LGS, SPS, and LPS rate schedules. It is an indirect billing determinant for calculating the "hours use" energy blocks for customers served on the LGS and SPS rate schedules.

Customer NCP Demand causes the utility to make long-term decisions concerning the size of the distribution system including and between that customer's meter and the first substation.[2] These Ameren Missouri decisions carry over to future customers.

[2] A large customer's NCP demand may have impacts beyond the first substation.

For example, if a welding shop were to be built in a vacant lot, Ameren Missouri would install a different (and more expensive) meter than if a house were being located there. The costs associated with the necessary upgrades would be borne by the customer requesting service to the extent that the net revenues that customer is expected to produce do not cover the costs. If the welding shop closes and a small insurance office moves in, it is very unlikely that Ameren Missouri would replace the lines, transformers, meters, and service drops with smaller infrastructure, unless distribution work happened to be occurring in the area and the items were in need of repair (or Ameren Missouri made an economic decision to replace them related to their level of net investment).

The costs that are reasonably related to customers' NCP Demand are those costs that are related to the demands the customer will exert on the local secondary distribution system for Residential, SGS, LGS, and Lighting customers, and the demands the customer will exert on the local primary distribution system for SPS and LPS customers. These costs vary very little over the course of a typical year, with two exceptions. First, if a customer increases demand such that additional infrastructure is required, the Ameren Missouri tariff outlines the allowances and contributions related to payments the customer will be required to make to address the costs of the infrastructure. Second, if Ameren Missouri replaces infrastructure in an area, it may increase or decrease the capabilities of the system related to existing, changed, or anticipated customer NCP demands.

2. Class NCP Demand, (the one hour interval during each month during which a studied rate class comprised of one or more rate schedule used the most energy in the relevant month) is a metric used in some Class Cost of Service Studies for allocating production capacity costs, transmission capacity costs, and distribution system costs. To the extent it is used for the allocation of production capacity costs, it is also relevant to the revenues obtained from the operation of generating facilities. It is not a direct billing determinant for any customer, and the costs that it is associated with do not vary within the year based on the level of NCP demand exerted by any class or rate schedule.

3. Class Coincident Peak Demand (the usage of each studied rate class during the hour at which the system recorded the highest usage during a month or year) is a metric used in some Class Cost of Service Studies for allocating production capacity costs,

transmission capacity costs, and distribution system costs. To the extent it is used for the allocation of production capacity costs, it is also relevant to the revenues obtained from the operation of generating facilities. It is not a direct billing determinant for any customer, and the costs that it is associated with do not vary within the year based on the level of demand coincident with peak exerted by any class or rate schedule. (The sum of the class loads is discussed as "System Peak Demand.)

4. System Peak Demand (typically the highest energy usage the system experienced during an hour of the year, or the system's load at the time that the relevant RTO experienced its highest energy usage during an hour of the year) limits the revenues Ameren Missouri is able to receive for its excess capacity through the MISO IM. It is not a determinant for any particular class. The MISO IM capacity requirement applicable to Ameren Missouri is forward looking for the year, based on projections, but the hour of Ameren Missouri's system peak cannot be known until after the applicable year's summer season has concluded. Note, in recent years Ameren Missouri has experienced relatively larger winter peaks, however, MISO as a whole continues strongly summer-peaking.

5. Customer Coincident Peak Demand (the maximum usage of a customer during a specified interval within a specified period, where the specified period encompasses conditions that are associated with system peaks ranging from the local distribution system to the RTO system) is not currently a billing determinant in use for a Missouri utility. Ideally, this metric would be useful for allocation to the classes and recovery from customers of those costs that do vary with either local system conditions or RTO requirements and pricing. For example, if Ameren Missouri were experiencing a need to increase the size of distribution system transformers due to heavy usage occurring on Summer afternoons, a reasonable recovery for that cost would be the highest hour of use a customer exerts on a system on ANY Summer afternoon. Similarly, the level of excess capacity Ameren Missouri receives revenues for through the MISO Resource Adequacy market is limited by the needs of Ameren Missouri to ensure capacity for its own customers at the time of MISO peak. A reasonable recovery (as a billing determinant) or allocation (for CCOS) would be the highest hour of use a customer exerts on the system on ANY Summer afternoon (for the billing determinant) allocated for

CCOS purposes on the sum of the highest hour of use all customers exerted on the system on ANY Summer afternoon (for the allocation).

The rationale is twofold. First, the hour that the summer peak occurred will be unknown until after the summer is over. Second, the NCP demands of customers are largely independent variables. While cumulative air conditioning load appears to be the largest driver of summer peak loads, the independent choices of homes and business to consume electricity during times of extreme heat reduces the diversity typically associated with customer NCP demands. Meaning, the decision of a final cumulative customer to switch on a lightbulb in a dim warehouse on a summer afternoon may be what distinguishes the hour of system peak from just another high-consumption hour. Only a subset of HVAC load will be present in that hour. It would not be reasonable to punitively bill those customers who happened to be running HVAC equipment in that hour versus identical conditions the day prior.

Q. How is each demand determined?

A. Customer Non-Coincident Peak Demand, is a determinant retained by the company's billing system for customers on the currently-structured LPS, SPS, and LGS tariffs. Limited data is available for customers served on other classes. Ameren Missouri has proposed use of Customer Coincident Peak Demand for an optional ToU rate. Staff supports development of this metric and determinant for all customers in all classes.

Class Non-Coincident Peak Demand, Class Coincident Peak Demand, and System Peak Demand are all developed as weather-normalized metrics from load research data. **As discussed by Staff Witness Michael L. Stahlman, Ameren Missouri encountered multiple issues with providing reliable load research data for use in this case. As Staff recommended in its direct CCOS Report, going forward Ameren Missouri should leverage AMI meter data to create 100% sampled load research data for use in future cases.**

Q. What is the relevance of a customer's NCP demand to the cost of Ameren Missouri's generation capacity or MISO IM resource adequacy?

A. A customer's NCP demand is not relevant to Ameren Missouri's generation capacity or MISO resource adequacy. The usage of a customer in the interval associated with the system peak is the only determinant relevant to Ameren Missouri's MISO resource adequacy or generation capacity requirements. There may have been a time where customer usage was so uniform that it could reasonably be assumed that a customer's NCP demand would coincide with system peak, but that is certainly not the case today. Therefore, it is no more reasonable to recover the costs associated with system peak demands via a customer's NCP demand than it is to recover those costs via a customer's energy consumption, and it is potentially less reasonable to do so.

NEW APPROACHES TO CCOS AND RATE STRUCTURES

Q. Is the customer cost of service study conducted by Mr. Wills a useful exercise?

A. Yes. While the actual study results provided in this case are unreliable due to the use of the company's CCOS as its basis, this study represents a useful expansion of the methods of examining customer cost causation.[3] Existing rate structures and CCOS studies are built on the premise that customers on a given rate schedule use the system in the same ways, with distinctions made only within the rate design itself for differences in cost recovery from customers served on the rate schedule with blunt measures such as NCP demand and load factors.

[3] Staff addresses its concerns with the Ameren Missouri classification of distribution plant in this testimony. Further Staff and other parties recommend that the Ameren Missouri revenue requirement calculation be modified. Finally, the loads and peaks that are the basis of the Ameren Missouri study allocation at the time of direct have been acknowledged by Ameren Missouri to be inaccurate.

Q. Was the company's customer cost of service study "top down," or "bottom up" in nature?

A. Mr. Wills' conducted his "top down" study as an extension of Mr. Hickman's CCOS. Meaning, Mr. Wills looked at the costs allocated to the residential class by Mr. Hickman, and further allocated them to the studied individual residential customers.

Q. Moving forward, is a bottom up study a useful exercise?

A. I believe so. A "bottom up" approach under which costs are assigned or allocated to determinates across classes – such as Customer Coincident Peak – will enable alignment of revenue responsibility to cost causation, regardless of a customer's class. Staff attempted to conduct a bottom up study early on in this case, but ran into data issues, as discussed in part by Mr. Stahlman. Ultimately, with data captured and retained with AMI metering, Staff is optimistic that relevant determinants for every (or nearly every) customer may be used to study the cost of serving customers, as opposed to serving classes of customers.

While only recently published by the Regulatory Assistance Project ("RAP"), this approach appears consistent with the direction advocated in the handbook "Electric Cost Allocation for a New Era," by Jim Lazar, Paul Chernick and William Marcus, edited by Mark LeBel, attached as Schedule SLKL-r1.

Q. What additional data is necessary to perform a study of this nature?

A. It is likely that a study could be built off of the load research data discussed by Mr. Wills. An ideal study would use actual hourly per customer data as its determinants to the extent possible. Additional transparency into the costs associated with Ameren Missouri's transmission and distribution system will be needed as a significant improvement over continued extrapolation of the dated Vandas study, as relied on by Mr. Wills and Mr. Hickman in this and prior cases. It is Staff's understanding that Ameren Missouri does not currently maintain its records in a way that facilitates identification of the following items:

1. The cost of the primary distribution system, including relevant transformers and substations, by voltage,
2. The cost of the secondary distribution system, , including relevant transformers and substations, by voltage,
3. The cost of the portions of the primary distribution system that are dedicated to serving individual customers receiving service at primary voltage, by voltage,
4. The costs of infrastructure offset by customer contributions pursuant to the line extension policy, by voltage and rate schedule,
5. The costs of meters by voltage and rate schedule.

Staff does understand that rights-of-way and substations often hold equipment associated with more than one voltage, and suggests that land, poles, or conduit that carry multiple lines be identified for allocation between primary and secondary as necessary from time to time in rate cases. A Reasonably implemented means of recording the information described above may be to require Ameren Missouri to retain records of the electric plant associated with each circuit. Investment that is associated with multiple circuits – for example if a higher voltage circuit shares right-of-way and poles with a lower voltage circuit – could be identified for allocation between those circuits as needed.

I am not an accountant, and I am not alleging that Ameren Missouri's current booking practices are inconsistent with the requirements of the USOA or any applicable accounting standards. However, these costs are associated with stationary objects, the use of which is known in stark detail by Ameren Missouri line personnel, and for which the net investment is projected to significantly increase in the near future. Staff is hopeful that a cost-effective tracking system can be implemented to more accurately identify these discrete costs in the manner identified above than is possible under the current USOA major account accounting.

Q. How precise is the historical practice of allocating costs via CCOS to classes to develop rate designs to accomplish recovery of those costs across determinants and rate schedules?

A. This practice is not at all precise. The CCOS process can be thought of as dividing out the check to tables at the end of a banquet, and rate design as divvying each table's check to the patrons at that table. The second step cannot be more accurate than allowed for by the first, and the loudest voices at the table will advocate for what most benefits them. Staff is hopeful that with the retention of hourly customer load data, better retention of infrastructure cost data, and the willingness of the Company and Commission to adopt new rate structures, customers will be billed more fairly than is possible under existing rate structures, and the changes that have occurred in the energy market in the last 15 years will finally be recognized and accurately reflected to customers. In essence, modern rate structures will likely obviate the need for a Class Cost of Service study as a separate exercise from assigning costs to customer bill components. Using the banquet example above, modern rate structures would better recover the cost of the extra guacamole from the customers eating the guacamole, and only the customers eating the guacamole, at the cost of the guacamole on the tab, while recovering the cost of each chair evenly from each customer, without penalizing or advantaging a given customer for who happens to sit by them.

Q. Could you provide an example to illustrate the disconnection and imprecision between CCOS and rate design?

A. Consider a hypothetical utility with only two classes, a General Service Class and a Residential Class, and a production capacity revenue requirement of $10 million. The characteristics of the General Service customers – as individuals – and the Residential Class are provided below:

			Demand During Summer Peaks	NCP Demand*	Energy Consumption
General Service Class	Customer A	Nighttime Usage, Year Round	10	100	437,835
	Customer B	Daytime Usage, Year Round	100	100	433,500
	Customer C	Daytime Usage, Summer Only	100	100	144,500
Residential Class			1,000	1,200	4,380,000
		*Sum of NCP demands of all Residential Customers			

A CCOS would result in allocation of approximately 17% of production capacity costs ($1.7 million) to the General Service Class, and 83% ($8.3 million) to the Residential Class.

If the General Service's rates are designed to recover the General Service class's allocation of production capacity costs from the NCP demand charge (or from the first blocks of an Hour's Use energy charge) the resulting allocation of production capacity costs per GS customer is provided below:

		Demand During Summer Peaks	NCP Demand*	Energy Consumption	Class Allocation of Capacity Costs		General Service Intra-Class Allocation of Capacity Costs	
Customer A	Nighttime Usage, Year Round	10	100	437,835			33%	$ 578,512
Customer B	Daytime Usage, Year Round	100	100	433,500	17%	$ 1,735,537	33%	$ 578,512
Customer C	Daytime Usage, Summer Only	100	100	144,500			33%	$ 578,512

This design causes each customer to provide revenues to cover production capacity costs on the basis of that customer's NCP, even though Customer A contributes much less than Customer B or Customer C to the need for production capacity. However, if the Demand During Summer Peaks is used to allocate the costs directly to the customers, as shown in the table below, Customer A contributes proportionate to Customer A's contribution to the need for capacity costs, and Customers B & C contribute additional revenues to cover their contribution to the need for capacity costs. Notice that the Residential class's responsibility remains the same.

			Demand During Summer Peaks	NCP Demand*	Energy Consumption	Class Allocation of Capacity Costs		Reasonable and Equitable Allocation of Capacity Costs	
General Service Class	Customer A	Nighttime Usage, Year Round	10	100	437,835	17%	$ 1,735,537	1%	$ 82,645
	Customer B	Daytime Usage, Year Round	100	100	433,500			8%	$ 826,446
	Customer C	Daytime Usage, Summer Only	100	100	144,500			8%	$ 826,446
Residential Class			1,000	1,200	4,380,000	83%	$ 8,264,463	83%	$ 8,264,463

The problem to be addressed by a customer cost of service study and modernized rate design is not necessarily to shift the class-level recovery that is indicated by a CCOS, it is to better align rate elements across rate schedules with the actual costs related to each customer for that element of service, regardless of the rate schedule on which the customer receives service. The customers most likely to receive lower bills through such a modernization of rate design are those with significant usage overnight and during the spring and fall. The customers most likely to receive higher bills through the modernization of rate design are those with heavy usage during summer afternoons and early evenings.

Q. Have you reviewed the timing of customer NCP by class relative to system peak?

A. Using Ameren Missouri's data, I analyzed the usage of the load research customers at the hour of system peak in each month, as a percent of that customer's NCP in that month. I then counted the number of customers at each level of percentage usage. For example, looking below at the residential class, in the month of January, 2 customers out of 87 experienced their NCP, or usage equal to their NCP at the hour of the system peak.[4] In the month of April, during the hour of system peak, 23 customers were using 20% of their NCP for

[4] For example, a customer's monthly NCP may be 12.5 kW, but that customer may use 12.5 kW in several hours during that month.

that month. The tabular data for each class is provided below, as well as a condensed graphical representation of this data for each class.

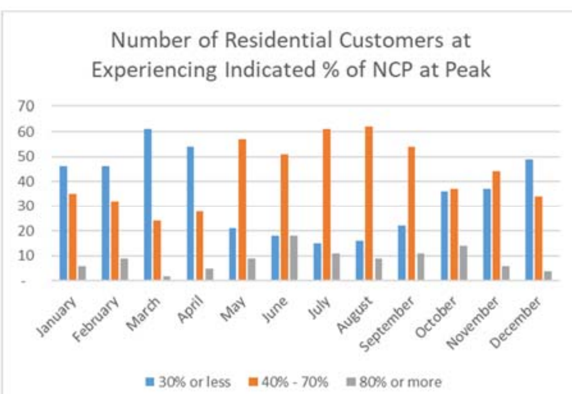
Residential	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
January	4	15	17	10	9	12	7	7	3	1	2
February	1	10	20	15	12	12	6	2	5	4	-
March	4	18	20	19	10	5	5	4	2	-	-
April	3	15	23	13	9	7	12	-	5	-	-
May	1	3	6	11	16	20	13	8	4	2	3
June	1	1	4	12	9	19	15	8	11	6	1
July	2	2	5	6	12	17	22	10	7	4	-
August	2	5	1	8	11	21	15	15	5	2	2
September	4	2	5	11	19	18	9	8	6	3	2
October	4	9	12	11	9	4	17	7	8	5	1
November	1	5	17	14	16	13	8	7	2	2	2
December	1	13	21	14	13	8	5	8	3	-	1

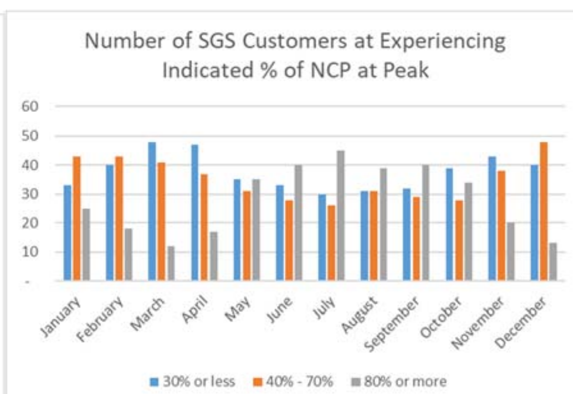
Small General Service	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
January	15	2	7	9	5	10	15	13	12	11	2
February	8	9	13	10	12	7	9	15	8	7	3
March	13	16	9	10	12	8	13	8	3	7	2
April	12	12	13	10	6	15	9	7	8	3	6
May	14	7	8	6	7	4	7	13	11	18	6
June	14	6	3	10	8	2	10	8	15	14	11
July	13	2	7	8	7	4	5	10	12	21	12
August	12	6	7	6	8	6	3	14	9	18	12
September	15	5	5	7	2	9	10	8	10	11	19
October	18	5	6	10	5	3	10	10	7	17	10
November	7	12	9	15	11	10	9	8	6	4	10
December	7	10	14	9	14	8	14	12	4	5	4

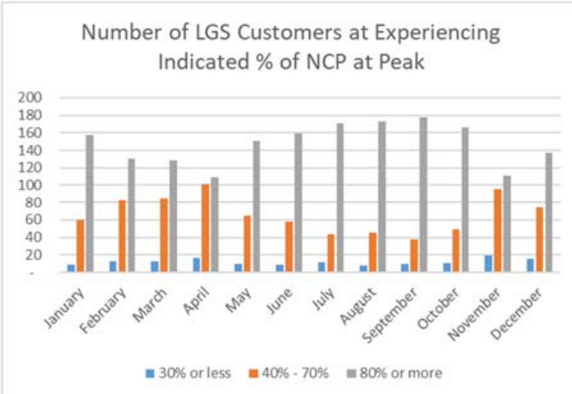
Large General Service	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
January	0	4	1	4	5	12	18	25	41	73	43
February	0	3	4	6	6	15	25	37	43	40	47
March	0	2	7	4	10	22	21	32	41	64	23
April	0	5	6	5	17	19	25	40	42	40	27
May	2	2	2	4	4	12	18	31	42	80	29
June	3	1	2	3	7	8	12	31	35	77	47
July	3	2	2	5	5	11	8	19	43	80	48
August	2	2	0	4	7	5	9	24	37	71	65
September	2	2	3	3	4	6	9	19	45	82	51
October	2	2	5	2	6	8	9	26	48	64	54
November	1	4	6	8	14	16	29	37	53	51	7
December	0	2	3	10	9	12	21	32	43	51	43

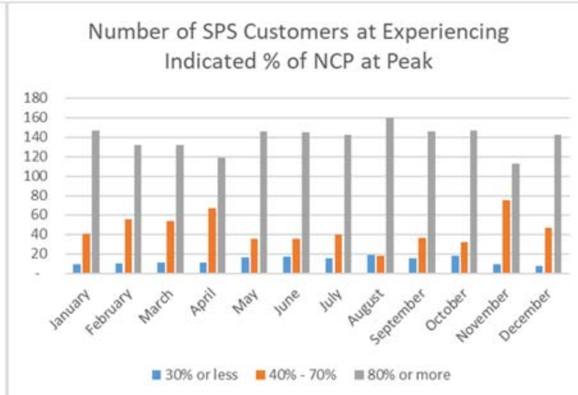
Small Primary Service	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
January	1	1	2	5	4	7	11	19	26	76	45
February	2	0	5	3	4	10	13	28	41	59	32
March	3	4	2	2	5	9	18	22	51	57	24
April	4	0	2	5	4	6	17	40	44	51	24
May	4	5	4	3	3	10	11	11	44	77	25
June	4	5	1	7	3	4	10	18	39	79	27
July	4	5	3	3	8	8	8	16	22	76	44
August	5	4	3	7	2	2	7	7	31	60	69
September	5	4	4	2	5	4	10	17	23	56	67
October	3	5	5	5	5	6	11	10	22	57	68
November	3	0	2	4	9	13	21	32	53	54	6
December	3	0	2	3	6	5	11	25	43	68	31

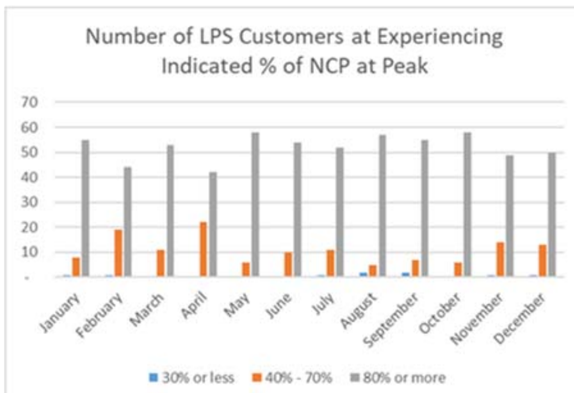
Large Primary Service	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
January	0	0	0	1	1	2	3	2	15	30	10
February	0	0	1	0	2	5	3	9	14	21	9
March	0	0	0	0	0	2	4	5	18	24	11
April	0	0	0	0	2	2	7	11	18	17	7
May	0	0	0	0	0	1	3	2	8	32	18
June	0	0	0	0	1	3	1	5	8	25	21
July	0	0	0	1	1	3	3	4	6	24	22
August	0	0	0	2	1	2	1	1	6	22	29
September	0	0	0	2	0	2	2	3	3	18	34
October	0	0	0	0	0	2	3	1	9	18	31
November	0	0	0	1	1	2	2	9	17	29	3
December	0	0	1	0	1	4	3	5	13	28	9











Q. By month, what percent of the studied load research served on each rate schedule experienced their NCP at the hour of system peak?

A. The results are provided in the table below. Only for one rate schedule in one month (LPS in September) did more than half of the studied customers on a rate schedule have usage meeting their NCP occur at the hour of system peak:[5]

[5] Many customers experience their NCP level of usage in multiple hours of a month.

	Residential	SGS	LGS	SPS	LPS
January	2%	2%	19%	23%	16%
February	0%	3%	21%	16%	14%
March	0%	2%	10%	12%	17%
April	0%	6%	12%	12%	11%
May	3%	6%	13%	13%	28%
June	1%	11%	21%	14%	33%
July	0%	12%	21%	22%	34%
August	2%	12%	29%	35%	45%
September	2%	19%	23%	34%	53%
October	1%	10%	24%	35%	48%
November	2%	10%	3%	3%	5%
December	1%	4%	19%	16%	14%

Q. What is the relevance of this exercise to the direct testimonies filed in this case?

A. This exercise demonstrates that use of NCP as a determinant for the recovery of "demand" related costs as advocated by MECG and MIEC is misplaced, and that Mr. Wills advocacy for modernization of rate structures is appropriate. It is also consistent with Mr. Chriss's advocacy for movement away from the hours use rate structure.

RESIDENTIAL RATE DESIGNS

Q. What is Ameren Missouri's recommended residential rate design in this case?

A. Beginning at page 6 of his direct testimony, Mr. Wills states that "[t]he Company recommends beginning a gradual transition, a journey if you will, to modernize its rate structure. The specific details of the recommendation in this case are:

- A default rate similar to the status quo, but with a $2 increase in the monthly customer charge to better reflect the cost of serving customers
- Implementation of two new TOU rate options, including:
    - A rate focused on EV drivers, encouraging them to charge their vehicles overnight when there is plenty of excess capacity on the system

- A rate focused on engaged customers who are willing to manage their whole home energy usage in order to reduce their bills along with their impact on the grid during peak usage times

- A pilot study of 3 part rates to understand how well customers understand, accept, and respond to them

- A continued dialogue over the next few rate proceedings to continue to progress to the point where the Company provides its customers with a variety of cost reflective rate options that meet customers' needs and desires for increased choice and control."

Q. Has any other party provided a residential rate design recommendation?

A. Yes, Avi Allison provides testimony on behalf of the Sierra Club, and Martin Hyman provides testimony on behalf of the Department of Energy. Mr. Hyman recommends the Commission establish clear goals and evaluation metrics for study of the proposed ToU designs, as well as establish customer education practices. Mr. Allison opposes Ameren Missouri's proposal to increase the residential customer charge, recommends increasing the peak period length of the "Smart Savers Rate," recommends establishment of a Critical Peak Pricing component to the "Smart Savers Rate," recommends establishment of a sub-metered EV rate, recommends increased customer education, and rejection of Ameren Missouri's proposed three-part rate, or in the alternative, alignment of the hours for the Coincident Peak determinant with that proposed by Sierra Club for the Smart Savers Rate.

Q. Does Staff have any immediate concerns with Ameren Missouri's residential proposals?

A. Yes. Staff expert Robin Kliethermes will discuss Ameren Missouri's proposed customer charge. Staff is generally supportive of giving customers options, but is concerned that seven Residential rate options will prove confusing to customers.

Q. Does Staff have any immediate concerns with Sierra Club's recommendations concerning Ameren Missouri's residential proposals?

A. Yes. Mr. Allison recommends incorporating a Critical Peak Pricing component to the Ameren Missouri-proposed "Smart Saver's" rate schedule, stating "CPP rates assess an extremely high price during only a small number of event hours per year. Customers are typically notified the day before an event. For example, a utility might call five CPP events during the year, each of which lasts for between two and four hours. During the events, electricity might be priced at $1.50 per kWh. CPP can easily be layered on top of a standard TOU rate, though additional consumer education efforts are essential for a rate that includes CPP. CPP can be used to concentrate recovery of peak-related costs on a small number of hours during which the system is actually at or near its peak. This reduces the magnitude of the peak-related costs that are left to be recovered through an on-peak TOU rate."[6]

Sierra Club does not actually propose that Ameren Missouri's ability to call CPP events be limited in quantity nor duration. If Ameren Missouri elects to call more CPP events than was anticipated when rates were designed Ameren Missouri would overcollect the "peak related" costs that the rate element was designed to recover. Similarly, if weather conditions are not conducive to calling the assumed number of CPP events Ameren Missouri would undercollect those costs. While Staff is generally supportive of rate designs that encourage peak shaving by accurately reflecting cost-causation, the costs that a CPP program may eventually reduce would generally flow back through the FAC as a benefit to all customers based on annual energy consumption with an approximate two year lag,[7] while the cost for on-peak consumption would

[6] Allison Direct, page 27.

[7] The reduced energy purchases would flow through the FAC based on energy consumption with an approximate one year lag.

be disproportionately borne by participating customers in real time. Further, it is not clear that the Commission has current authority to implement a program to balance the revenues to avoid this disparity nor to review the prudency of the calling of CPP events by Ameren Missouri.

Mr. Allison also expresses concern with the Ameren Missouri requirement that customer bills be rendered using utility meters. He states that utilities in other jurisdictions are in various stages of development and implementation of programs to bill customers based on usage records obtained from electric charging equipment as opposed to the "whole house" usage recorded by the utility's meter. He goes on to recommend that Ameren Missouri "promptly investigate and develop a sub-metering option for its EV Savers customers."[8]

As discussed in the CCOS Report, Staff generally recommends a transition to a ToU residential rate design that closely resembles the Ameren Missouri "Electric Vehicle" rate, so this issue may be moot within a matter of a year or two.[9] However, Staff does not recommend that a customer's usage, as captured through a single meter, be bifurcated for billing on multiple rate schedules based on usage data obtained from third-party vendors' equipment that is not under the control of Ameren Missouri.[10] Additionally, on advice of counsel, Staff is concerned that such single meter usage bifurcation for billing on multiple rate schedules based on a particular end use as opposed to a customer's characteristics of consumption would be unduly discriminatory and impermissible under the Laundry line of cases governing end-use rates in Missouri.

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[8] Allison Direct, page 30-31.

[9] Ameren Missouri does not propose to restrict the availability of this rate schedule to customers with EV charging equipment. As discussed below, Staff recommends the name be revised to broaden the appeal of this rate to Ameren Missouri's customers.

[10] Staff has no objection to a customer electing to request the installation of an additional meter to enable receipt of service on multiple rate schedules within a residence.

Mr. Allison also recommends that Ameren Missouri collect and make available detailed information regarding the effectiveness of the "Ultimate Saver's" pilot rate.[11] As discussed by Robin Kliethermes, Staff generally agrees that clear metrics are necessary for program evaluation and that enhanced customer education and transparency is important.[12]

Q. How many rate options would exist for residential customers under Ameren Missouri's proposal?

A. Under Ameren Missouri's proposed "Smart Saver," and EV schedules customers may choose to participate either year-round, or for only four months of the year, constituting four options. The grandfathered ToU, the "Ultimate Saver" program, and the standard rate provide an additional three options.

Q. If a customer elects to participate for only four months of the year in the "Smart Saver" or EV schedule, which months would be subject to the ToU rate?

A. Due to the billing cycle alignment issue identified by Staff in the CCOS Report at page 39, the four months that would be subject to the ToU rate would vary, based on the billing cycle on which the customer is billed. For some customers, the applicable period would be the calendar months of April – July, for some customers the applicable period would be the calendar months of June – September, with all possible variations in between.

Q. What are the residential rate options proposed by Ameren Missouri, and how do they compare to each other?

A. The standard residential rate schedule proposed by Ameren would reflect a customer charge of $11 a month, a low income charge of $0.04 a month, a charge for all energy

[11] Allison Direct page 34.

[12] Mr. Hyman on behalf of DE also raises concerns with the overall information and education surrounding the proposed rate options.

for a "summer" billing cycle of $0.1151/kWh, and for non-summer billing months, the first 750 kWh would be billed at $0.08/kWh, and all remaining kWh would be billed at $0.0551/kWh. Rates reflecting this non-summer billing month standard declining design are indicated with the letters "SD" in the graphic below. The graphic below depicts the cents per kWh by hour applicable to each residential rate design, and also to the SGS ToU design, which would be applicable to garages that are not attached to homes pursuant to the Ameren Missouri restrictions on availability of the Residential rate schedules. Additionally, the Electric Vehicle rate is available to customers without AMI meters, but an additional charge of $1.50/month is assessed; and the Ultimate Savers rate includes Coincident Peak demand charges of $6.86/kW for summer billing months, and $2.93/kW for non-summer billing months.

	Grandfathered ToU		"Smart Saver" Full Year		"Smart Saver" 4 Month		Electric Vehicle Full Year		Electric Vehicle 4 Month		Ultimate Saver		SGS ToU Option	
	Summer Weekdays	Summer Weekends	Summer Weekdays	Summer Weekends	Summer Weekdays	Summer Weekends	Summer Weekdays	Summer Weekends	Summer Weekdays	Summer Weekends	Summer Weekdays	Summer Weekends	Summer Weekdays	Summer Weekends
12:00 AM	0.072	0.072	0.0537	0.0537	0.0537	0.0537	0.0539	0.0539	0.0539	0.0539	0.0427	0.0427	0.0634	0.0634
1:00 AM	0.072	0.072	0.0537	0.0537	0.0537	0.0537	0.0539	0.0539	0.0539	0.0539	0.0427	0.0427	0.0634	0.0634
2:00 AM	0.072	0.072	0.0537	0.0537	0.0537	0.0537	0.0539	0.0539	0.0539	0.0539	0.0427	0.0427	0.0634	0.0634
3:00 AM	0.072	0.072	0.0537	0.0537	0.0537	0.0537	0.0539	0.0539	0.0539	0.0539	0.0427	0.0427	0.0634	0.0634
4:00 AM	0.072	0.072	0.0537	0.0537	0.0537	0.0537	0.0539	0.0539	0.0539	0.0539	0.0427	0.0427	0.0634	0.0634
5:00 AM	0.072	0.072	0.0537	0.0537	0.0537	0.0537	0.0539	0.0539	0.0539	0.0539	0.0427	0.0427	0.0634	0.0634
6:00 AM	0.072	0.072	0.0845	0.0845	0.0845	0.0845	0.1355	0.1355	0.1355	0.1355	0.0427	0.0427	0.0634	0.0634
7:00 AM	0.072	0.072	0.0845	0.0845	0.0845	0.0845	0.1355	0.1355	0.1355	0.1355	0.0427	0.0427	0.0634	0.0634
8:00 AM	0.072	0.072	0.0845	0.0845	0.0845	0.0845	0.1355	0.1355	0.1355	0.1355	0.0427	0.0427	0.0634	0.0634
9:00 AM	0.072	0.072	0.0845	0.0845	0.0845	0.0845	0.1355	0.1355	0.1355	0.1355	0.0427	0.0427	0.0634	0.0634
10:00 AM	0.072	0.072	0.0845	0.0845	0.0845	0.0845	0.1355	0.1355	0.1355	0.1355	0.0427	0.0427	0.1556	0.0634
11:00 AM	0.072	0.072	0.0845	0.0845	0.0845	0.0845	0.1355	0.1355	0.1355	0.1355	0.0427	0.0427	0.1556	0.0634
12:00 PM	0.072	0.072	0.0845	0.0845	0.0845	0.0845	0.1355	0.1355	0.1355	0.1355	0.0427	0.0427	0.1556	0.0634
1:00 PM	0.072	0.072	0.0845	0.0845	0.0845	0.0845	0.1355	0.1355	0.1355	0.1355	0.0427	0.0427	0.1556	0.0634
2:00 PM	0.2882	0.072	0.0845	0.0845	0.0845	0.0845	0.1355	0.1355	0.1355	0.1355	0.0427	0.0427	0.1556	0.0634
3:00 PM	0.2882	0.072	0.3214	0.0845	0.3214	0.0845	0.1355	0.1355	0.1355	0.1355	0.2515	0.2515	0.1556	0.0634
4:00 PM	0.2882	0.072	0.3214	0.0845	0.3214	0.0845	0.1355	0.1355	0.1355	0.1355	0.2515	0.2515	0.1556	0.0634
5:00 PM	0.2882	0.072	0.3214	0.0845	0.3214	0.0845	0.1355	0.1355	0.1355	0.1355	0.2515	0.2515	0.1556	0.0634
6:00 PM	0.2882	0.072	0.3214	0.0845	0.3214	0.0845	0.1355	0.1355	0.1355	0.1355	0.2515	0.2515	0.1556	0.0634
7:00 PM	0.072	0.072	0.0845	0.0845	0.0845	0.0845	0.1355	0.1355	0.1355	0.1355	0.2515	0.2515	0.1556	0.0634
8:00 PM	0.072	0.072	0.0845	0.0845	0.0845	0.0845	0.1355	0.1355	0.1355	0.1355	0.0427	0.0427	0.1556	0.0634
9:00 PM	0.072	0.072	0.0845	0.0845	0.0845	0.0845	0.1355	0.1355	0.1355	0.1355	0.0427	0.0427	0.1556	0.0634
10:00 PM	0.072	0.072	0.0537	0.0537	0.0537	0.0537	0.0539	0.0539	0.0539	0.0539	0.0427	0.0427	0.0634	0.0634
11:00 PM	0.072	0.072	0.0537	0.0537	0.0537	0.0537	0.0539	0.0539	0.0539	0.0539	0.0427	0.0427	0.0634	0.0634

	Non-Summer Weekdays	Non-Summer Weekends	Non-Summer Weekdays	Non-Summer Weekends	Non-Summer Weekdays	Non-Summer Weekends	Non-Summer Weekdays	Non-Summer Weekends	Non-Summer Weekdays	Non-Summer Weekends	Non-Summer Weekdays	Non-Summer Weekends	Non-Summer Weekdays	Non-Summer Weekends
12:00 AM	SD	SD	0.0478	0.0478	SD	SD	0.0477	0.0477	SD	SD	0.0389	0.0389	0.047	0.047
1:00 AM	SD	SD	0.0478	0.0478	SD	SD	0.0477	0.0477	SD	SD	0.0389	0.0389	0.047	0.047
2:00 AM	SD	SD	0.0478	0.0478	SD	SD	0.0477	0.0477	SD	SD	0.0389	0.0389	0.047	0.047
3:00 AM	SD	SD	0.0478	0.0478	SD	SD	0.0477	0.0477	SD	SD	0.0389	0.0389	0.047	0.047
4:00 AM	SD	SD	0.0478	0.0478	SD	SD	0.0477	0.0477	SD	SD	0.0389	0.0389	0.047	0.047
5:00 AM	SD	SD	0.0478	0.0478	SD	SD	0.0477	0.0477	SD	SD	0.0389	0.0389	0.047	0.047
6:00 AM	SD	SD	0.1636	0.059	SD	SD	0.0782	0.0782	SD	SD	0.1405	0.0389	0.047	0.047
7:00 AM	SD	SD	0.1636	0.059	SD	SD	0.0782	0.0782	SD	SD	0.1405	0.0389	0.047	0.047
8:00 AM	SD	SD	0.059	0.059	SD	SD	0.0782	0.0782	SD	SD	0.0389	0.0389	0.047	0.047
9:00 AM	SD	SD	0.059	0.059	SD	SD	0.0782	0.0782	SD	SD	0.0389	0.0389	0.047	0.047
10:00 AM	SD	SD	0.059	0.059	SD	SD	0.0782	0.0782	SD	SD	0.0389	0.0389	0.1025	0.047
11:00 AM	SD	SD	0.059	0.059	SD	SD	0.0782	0.0782	SD	SD	0.0389	0.0389	0.1025	0.047
12:00 PM	SD	SD	0.059	0.059	SD	SD	0.0782	0.0782	SD	SD	0.0389	0.0389	0.1025	0.047
1:00 PM	SD	SD	0.059	0.059	SD	SD	0.0782	0.0782	SD	SD	0.0389	0.0389	0.1025	0.047
2:00 PM	SD	SD	0.059	0.059	SD	SD	0.0782	0.0782	SD	SD	0.0389	0.0389	0.1025	0.047
3:00 PM	SD	SD	0.059	0.059	SD	SD	0.0782	0.0782	SD	SD	0.0389	0.0389	0.1025	0.047
4:00 PM	SD	SD	0.059	0.059	SD	SD	0.0782	0.0782	SD	SD	0.0389	0.0389	0.1025	0.047
5:00 PM	SD	SD	0.059	0.059	SD	SD	0.0782	0.0782	SD	SD	0.0389	0.0389	0.1025	0.047
6:00 PM	SD	SD	0.1636	0.059	SD	SD	0.0782	0.0782	SD	SD	0.1405	0.0389	0.1025	0.047
7:00 PM	SD	SD	0.1636	0.059	SD	SD	0.0782	0.0782	SD	SD	0.1405	0.0389	0.1025	0.047
8:00 PM	SD	SD	0.059	0.059	SD	SD	0.0782	0.0782	SD	SD	0.0389	0.0389	0.1025	0.047
9:00 PM	SD	SD	0.059	0.059	SD	SD	0.0782	0.0782	SD	SD	0.0389	0.0389	0.1025	0.047
10:00 PM	SD	SD	0.0478	0.0478	SD	SD	0.0477	0.0477	SD	SD	0.0389	0.0389	0.047	0.047
11:00 PM	SD	SD	0.0478	0.0478	SD	SD	0.0477	0.0477	SD	SD	0.0389	0.0389	0.047	0.047

Q. What are Staff's concerns with the Grandfathered ToU rate?

A. Because the ToU option applies only to summer billing month usage, the pricing signal and cost-based recovery of the rate exists only for 1/3 of the year. The on-peak period is quite short, and the differential of off-peak to on-peak usage is quite high. Because the off-peak price is only a 37% discount to the standard rate, and the on-peak price is a 150% premium to the standard rate, Staff is concerned that customers would only opt-in to this optional rate if they were already using minimal energy during the on-peak period. The reasonableness of this rate is also dependent on the billing cycle on which a participating customer is billed. Staff is not aware of a cost basis for charging $0.28 per kWh for energy consumed in April, particularly while similarly situated customers on a different billing cycle will be paying less than 6 cents for energy consumed in the same hour under the proposed Ameren Missouri residential rate design.

Application of the final revenue requirement, billing determinants, and customer charge determined by the Commission in this rate case will impact the ultimate prices assigned to each period's rate.

Q. What are Staff's concerns with the Smart Savers rate?

A. The structure of this rate appears generally reasonable. Staff shares Sierra Club's concerns that the summer on-peak period would likely benefit from the addition of the 2:00 pm hour. Subject to Staff's concern that the Ameren Missouri load data is generally unreliable, provided in the table below are the Residential and System average maximum usages for each hour by month, and the percent of that average maximum that occurs as an average by hour for 2:00 pm through 6:00 pm.

	January	February	March	April	May	June	July	August	September	October	November	December
Residential Max	67,532	54,650	42,653	35,430	46,424	63,625	84,523	80,642	55,407	38,360	46,064	63,804
System Max	137,551	114,882	103,612	95,988	115,282	131,396	168,987	163,013	129,480	102,155	108,800	130,718
Residential % of Max at 2:00	84%	87%	90%	85%	79%	81%	86%	82%	83%	84%	79%	81%
Residential % of Max at 3:00	83%	86%	88%	85%	83%	86%	90%	87%	87%	86%	79%	80%
Residential % of Max at 4:00	85%	87%	87%	87%	87%	90%	94%	91%	92%	88%	81%	83%
Residential % of Max at 5:00	91%	92%	92%	92%	93%	96%	98%	96%	97%	94%	89%	91%
Residential % of Max at 6:00	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
System % of Max at 2:00	93%	96%	100%	100%	96%	95%	96%	95%	96%	100%	92%	91%
System % of Max at 3:00	93%	95%	98%	99%	97%	97%	98%	97%	98%	100%	91%	90%
System % of Max at 4:00	93%	95%	97%	99%	99%	99%	99%	99%	99%	99%	91%	91%
System % of Max at 5:00	95%	96%	97%	99%	100%	100%	100%	100%	100%	99%	94%	95%
System % of Max at 6:00	100%	100%	99%	100%	100%	100%	99%	99%	99%	99%	100%	100%

While the average 2:00 pm usage tends to be lower than that of the other hours, a principle method by which a customer will reduce summer on-peak energy consumption is through precooling the home. That will tend to increase usages in the hour prior to the on-peak period start. Staff is concerned that a new spike may be encouraged that would push the 2:00 pm usage, and recommends that shifting the pre-cooling load to the 1:00 pm interval would be preferable. This would also reduce the on-peak to intermediate-peak differential. Staff is concerned that the size of this differential will discourage participation in this opt-in rate.

Staff is again concerned that the misalignment of certain billing cycles with calendar months would send the unreasonable price signal of some customers being charged $0.32/kWh for energy used in the calendar month of April. Further, for the non-summer design, Staff recommends the design would send an improved price signal and better reflect cost causation if only the period of approximately November 15 – March 15 were subject to the indicated three-period price, with the “spring” and “fall” subject to only off-peak and intermediate pricing. Also, Staff has not observed loading conditions that would support discontinuance of on-peak pricing for weekends and holidays as distinct from weekdays.

Application of the final revenue requirement, billing determinants, and customer charge determined by the Commission in this rate case will impact the ultimate prices assigned to each period’s rate.

Q. What are Staff's concerns with the Electric Vehicle rate?

A. Staff recommends the rate be renamed because the general design is a sound ToU rate structure, and it is available to customers who do not have AMI metering. This rate structure and rate design is generally reasonable, and would cause customers using energy in relatively higher energy cost hours and hours when distribution system utilization is high to bear those costs. This rate structure will be easy for an average customer to understand and does not require sophisticated technology to leverage, nor is it likely to create new unintentional peaks. This rate design is not overly punitive to customers who are unable or unwilling to shift their usage to lower-priced hours.

Staff is again concerned that the misalignment of certain billing cycles with calendar months would send the unpredictable treatment of some customers being charged $0.1355/kWh for April on-peak usage while other customers will be charged $0.0782, depending on billing cycle. Staff recommends the design would send an improved price signal and better reflect cost causation if the period of approximately November 15 – March 15 were subject to slightly higher on-peak rates, with slightly lower pricing for the "spring" and "fall" off peak periods.

Application of the final revenue requirement, billing determinants, and customer charge determined by the Commission in this rate case will impact the ultimate prices assigned to each period's rate.

Q. What is Staff's concern with the SGS ToU rate proposal?

A. While it is certainly not the case that all SGS customers charge electric vehicles, it is important to recall that under the Ameren Missouri residential tariff, detached garages and similar structures are not eligible for the residential rate schedules and are instead served on the SGS rate schedule. Staff recommends a convergence of the Residential EV ToU design and the SGS ToU design, with the result available to both residential and SGS customers. While Staff understands the desirability of aligning the SGS ToU rate with the current Rider I designations of on and off peak, Staff believes that commercial and industrial SGS customers will be more likely to understand a misalignment in on-peak times than will residential customers with detached garages or other outbuildings that are served on SGS. Staff is not opposed to the creation of an SGS subschedule or rate to align ToU periods for these different circumstances where a particular customer may have multiple accounts served on various schedules, such as a residential customer with a detached garage versus an LGS customer who may add an SGS account for a separately metered parking lot kiosk.

Q. What are Staff's concerns with the Ultimate Savers rate?

A. Staff shares the Sierra Club's concerns regarding the desirability of including the 2:00 summer hour in the on-peak period. Staff is again concerned about unreasonable treatment of usage occurring in April and May due to the billing cycle alignment issue, and urges the subdivision of the non-summer billing period into shoulder and winter periods, and elimination of separate treatment for weekends and holidays. However, in general, the rate structure is well-thought out, and if broadly implemented (and reasonably designed based on the costs and determinants presented in each applicable rate case) would result in accurate recovery of costs from cost causers as well as encourage customer behaviors to lower overall costs.

Application of the final revenue requirement, billing determinants, and customer charge determined by the Commission in this rate case will impact the ultimate prices assigned to each period's rate.

Q. Is the window for the coincident peak demand appropriate?

A. A more precise window for coincident peak demand would vary by season. In the interest of keeping this somewhat complicated rate structure more understandable to customers, I consider it reasonable to maintain one time period year round. However, if a shorter window is determined appropriate for the summer calendar months, I am concerned that Sierra Club's recommendation to align the period with their recommended on-peak ToU period of 2:00 – 7:00 could have unintended consequences. Given the significant summer on-peak / off-peak differential proposed by Ameren Missouri, it is not unlikely that customers may create a new peak through shifting usage to either the 1:00 hour (precooling load) or the 8:00 hour (laundry and dishwashing load). For this reason, I recommend the coincident peak demand be determined using at least an hour before and an hour after the on-peak period. I am concerned that the resulting summer demand rate may be unreasonably high if the associated determinates are so modified, but those results will depend in part on the Commission's orders on other matters such as customer charge and residential revenue responsibility.

Q. Why is Staff's non-ToU residential rate design more reasonable than that proposed by Ameren Missouri?

A. While Staff has generally testified against inclining block rates, this case presents a unique opportunity to maintain the effective tariffed rate for second block usage, and simply discount the rate applicable to each month's initial usage. By moving to an inclining block design in the summer that maintains the existing effective tail block charge while reducing the first block charge, and flattening the non-summer rates by maintaining the existing effective tail block charge while reducing the first block charge on the residential Non-ToU rate schedule, the resulting rates will cause customers to begin to experience bills that for many will be more similar to those that would be produced under Staff's recommended ToU rate design.

The resulting incline/flattening will also serve to make the ToU rate options more attractive to customers with higher usage.

CUSTOMER BILL HISTORY, CLASS COST OF SERVICE, AND THE LGS, SPS, AND LPS RATE SCHEDULES

Q MECG asserts that "analysis for FERC Form 1 data shows that between 2008 and 2018, Ameren's reported revenue per kWh sold to LGS customers has increased from $0.0563/kWh to $0.0847/kWh, an increase of 50.3 percent."[13] Is the result of dividing the total dollars of revenue provided by customers on a given rate schedule by the kWh sold to customers on that rate schedule ten years ago relevant to any question before the Commission in this proceeding?

A. No. It may be informative for the Commission to review information related to shifts in revenue responsibility between various customers on various rate schedules over time, particularly as it relates to avoiding unnecessary rate switching or causing rate shock. However, there are better metrics of the impact of rate design on customers than class-average revenue per kWh. This metric is particularly unhelpful for considerations of class cost of service and rate design, because it fails to account for the changing customer base (1) due to changes in customer characteristics and (2) due to changes in the total numbers of customers receiving service whether due to rate switching or due to customer growth/loss.

Q. In what ways does the metric of class-average revenue per kWh provide a misleading signal concerning the bills experienced by customers within a class?

[13] Chriss direct, page 6.

A. To illustrate the misleading signal provided by this metric, in the following examples we will review the changes to the "LGS Average $/kWh" produced by varying customers and customer characteristics of a very small hypothetical class.

Example 1	Annual Bill	kWh	$/kWh	**Example 2a**	Annual Bill	kWh	$/kWh
LGS Customer 1	$ 3,500	50,000	$ 0.070	**LGS Customer 1**	**$ 7,000**	**100,000**	**$ 0.070**
LGS Customer 2	$ 3,500	50,000	$ 0.070	LGS Customer 2	$ 3,500	50,000	$ 0.070
LGS Customer 3	$ 2,000	50,000	$ 0.040	LGS Customer 3	$ 2,000	50,000	$ 0.040
LGS Customer 4	$ 2,000	50,000	$ 0.040	LGS Customer 4	$ 2,000	50,000	$ 0.040
LGS Average $/kWh	$ 11,000	200,000	**$ 0.055**	LGS Average $/kWh	$ 14,500	250,000	**$ 0.058**

In Example 1, the class-average revenue per kWh produced is $0.055 per kWh. In Example 2a, we see that Customer 1 has doubled usage. While the other customers' bills have not changed, the LGS Average $/kWh has increased to $0.058. This result is reproduced below in Example 2b, by the addition of another customer, LGS Customer 5.

Example 2b	Annual Bill	kWh	$/kWh	**Example 2c**	Annual Bill	kWh	$/kWh
LGS Customer 1	$ 3,500	50,000	$ 0.070	**LGS Customer 1**	**$ -**	**-**	**$ 0.070**
LGS Customer 2	$ 3,500	50,000	$ 0.070	LGS Customer 2	$ 3,500	50,000	$ 0.070
LGS Customer 3	$ 2,000	50,000	$ 0.040	LGS Customer 3	$ 2,000	50,000	$ 0.040
LGS Customer 4	$ 2,000	50,000	$ 0.040	LGS Customer 4	$ 2,000	50,000	$ 0.040
LGS Customer 5	**$ 3,500**	**50,000**	**$ 0.070**	LGS Average $/kWh	$ 7,500	150,000	**$ 0.050**
LGS Average $/kWh	$ 14,500	250,000	**$ 0.058**				

As in Example 1, in Example 2b, no other customer's bill has changed, but the class-average revenue per kWh has increased by 5.45%. However, as illustrated in Example 2c, above, the loss of Customer 1 results in a decrease of 9.1% to the class-average revenue per kWh.

Q. Is it likely that these changes in customer counts and customer characteristics would result in changes in the costs allocated or assigned to the LGS class in the next rate case?

A. Yes. However, those potential changes would not impact the bills paid by Customer 2, 3, and 4 until the rate schedule under which they are billed is changed. If the rates are appropriately designed, and all else remained equal, it is likely that the bill changes experienced by Customers 2, 3, and 4 would be minimal and reflect only the minor change in the company's overall sales.

Q. Can changes to rate design in rate cases result in some customers paying higher bills while other customers on the same rate schedule pay lower bills?

A. Yes. As illustrated in Example 3 below, not only can customers within a class experience vastly different impacts from a rate case due to changes in rate design, but customers can experience such impacts without change to the resulting class-average revenue per kWh.

Example 1	Annual Bill	kWh	$/kWh	**Example 3**	Annual Bill	kWh	$/kWh
LGS Customer 1	$ 3,500	50,000	$ 0.070	**LGS Customer 1**	**$ 3,850**	**50,000**	**$ 0.077**
LGS Customer 2	$ 3,500	50,000	$ 0.070	LGS Customer 2	$ 3,500	50,000	$ 0.070
LGS Customer 3	$ 2,000	50,000	$ 0.040	LGS Customer 3	$ 2,000	50,000	$ 0.040
LGS Customer 4	$ 2,000	50,000	$ 0.040	**LGS Customer 4**	**$ 1,650**	**50,000**	**$ 0.033**
LGS Average $/kWh	$ 11,000	200,000	**$ 0.055**	LGS Average $/kWh	$ 11,000	200,000	**$ 0.055**

In Example 3, Customer 1's bill was increased by 10%, Customer 4's bill was decreased by 17.5%, and the metric of class-average revenue per kWh remained unchanged.

Q. Is there a more reasonable means of reviewing the impact of the last 12 years of Ameren Missouri rate cases on customers?[14]

A. While no metric is perfect, it is probably most useful to review the bills or average $/kWh that would be experienced by a given customer with that customer's characteristics held constant over time. Given the size of Ameren Missouri's customer base and classes, it is impossible to accurately summarize these impacts for all potential customers. Further, it is possible that a customer would change rate schedules over this time due to changes in the rate designs of the relative schedules.

[14] MEEIA, RESRAM, and FAC charges are not reflected in the bills and average rates discussed throughout this testimony.

To facilitate these comparisons, Staff created a set of Customer Profiles, and priced out the bills for those customers from the final rates promulgated from each rate case since Case No. ER-2007-0002. For example, the bills produced by the studied Residential Profiles are provided below:

	ER-2007-0002	ER-2008-0318	ER-2010-0036	ER-2011-0028	ER-2012-0166	ER-2014-0258	ER-2016-0179	Temp. Tax Reduction
Residential Flat	$ 817	$ 882	$ 988	$ 1,079	$ 1,156	$ 1,219	$ 1,260	$ 1,186
1,500 ft Home w/ Space Heat	$ 1,015	$ 1,098	$ 1,230	$ 1,346	$ 1,443	$ 1,525	$ 1,577	$ 1,480
Large Home AC only	$ 1,161	$ 1,257	$ 1,408	$ 1,542	$ 1,653	$ 1,748	$ 1,808	$ 1,699
Small Apt w/ Space Heat	$ 840	$ 907	$ 1,016	$ 1,110	$ 1,188	$ 1,254	$ 1,299	$ 1,224

To facilitate comparisons across customers of very different sizes, Staff divided the total bills described above by the kWh of each customer. This produces an experienced average $/kWh that can be displayed on a graph with a readable scale when comparing the bill one may experience with a small apartment to the bill one may experience when participating in substantial industrial manufacturing.

The experienced average $/kWh by Customer Profile are provided below, as well as an indication of the % change experienced from the final rates promulgated in Case No. ER-2007-0002 to the tariffed rates in effect today, with and without the inclusion of the Temporary Tax Rider. Percent changes in excess of 50% are highlighted in red, and percent changes lower than 35% are highlighted in green.

continued on next page

	ER-2007-0002	ER-2008-0318	ER-2010-0036	ER-2011-0028	ER-2012-0166	ER-2014-0258	ER-2016-0179	Temp. Tax Reduction	% Change without Tax Impact	% Change with Tax Impact
Residential Flat	$ 0.068	$ 0.073	$ 0.082	$ 0.090	$ 0.096	$ 0.102	$ 0.105	$ 0.099	54%	45%
1,500 ft Home w/ Space Heat	$ 0.065	$ 0.070	$ 0.079	$ 0.086	$ 0.093	$ 0.098	$ 0.101	$ 0.095	55%	46%
Large Home AC only	$ 0.066	$ 0.071	$ 0.080	$ 0.088	$ 0.094	$ 0.099	$ 0.103	$ 0.097	56%	46%
Small Apt w/ Space Heat	$ 0.070	$ 0.076	$ 0.085	$ 0.092	$ 0.099	$ 0.104	$ 0.108	$ 0.102	55%	46%
SGS Flat	$ 0.067	$ 0.072	$ 0.081	$ 0.085	$ 0.091	$ 0.095	$ 0.099	$ 0.093	47%	39%
SGS 24 Hour Retail	$ 0.063	$ 0.068	$ 0.076	$ 0.080	$ 0.085	$ 0.089	$ 0.092	$ 0.087	47%	38%
SGS Office Use with HVAC	$ 0.065	$ 0.070	$ 0.079	$ 0.083	$ 0.089	$ 0.093	$ 0.096	$ 0.091	47%	38%
SGS 2nd Metered Residential	$ 0.084	$ 0.090	$ 0.102	$ 0.106	$ 0.113	$ 0.118	$ 0.124	$ 0.118	48%	41%
Small LGS Low Load Factor Winter Peak	$ 0.065	$ 0.065	$ 0.070	$ 0.077	$ 0.081	$ 0.090	$ 0.093	$ 0.089	43%	36%
Small LGS High Load Factor Winter Peak	$ 0.044	$ 0.044	$ 0.047	$ 0.052	$ 0.055	$ 0.061	$ 0.063	$ 0.058	42%	32%
Small LGS Low Load Factor Flat Usage	$ 0.068	$ 0.068	$ 0.073	$ 0.080	$ 0.084	$ 0.094	$ 0.097	$ 0.093	43%	36%
Small LGS High Load Factor Flat Usage	$ 0.044	$ 0.044	$ 0.047	$ 0.052	$ 0.055	$ 0.061	$ 0.063	$ 0.058	42%	32%
Large LGS Low Load Factor Winter Peak	$ 0.069	$ 0.069	$ 0.074	$ 0.082	$ 0.086	$ 0.096	$ 0.099	$ 0.094	43%	36%
Large LGS High Load Factor Winter Peak	$ 0.043	$ 0.043	$ 0.047	$ 0.051	$ 0.054	$ 0.060	$ 0.062	$ 0.057	42%	32%
Large LGS Low Load Factor Flat Usage	$ 0.065	$ 0.065	$ 0.070	$ 0.077	$ 0.081	$ 0.091	$ 0.094	$ 0.089	43%	36%
Large LGS High Load Factor Flat Usage	$ 0.043	$ 0.043	$ 0.047	$ 0.051	$ 0.054	$ 0.060	$ 0.062	$ 0.057	42%	32%
Small SPS Low Load Factor Winter Peak	$ 0.067	$ 0.072	$ 0.079	$ 0.083	$ 0.089	$ 0.093	$ 0.093	$ 0.088	39%	32%
Small SPS High Load Factor Winter Peak	$ 0.044	$ 0.047	$ 0.052	$ 0.054	$ 0.058	$ 0.061	$ 0.058	$ 0.054	33%	23%
Small SPS Low Load Factor Flat Usage	$ 0.070	$ 0.075	$ 0.082	$ 0.086	$ 0.093	$ 0.097	$ 0.101	$ 0.097	45%	39%
Small SPS High Load Factor Flat Usage	$ 0.044	$ 0.047	$ 0.052	$ 0.054	$ 0.058	$ 0.061	$ 0.063	$ 0.058	43%	33%
Large SPS Low Load Factor Winter Peak	$ 0.065	$ 0.070	$ 0.077	$ 0.081	$ 0.087	$ 0.091	$ 0.090	$ 0.086	38%	31%
Large SPS High Load Factor Winter Peak	$ 0.042	$ 0.045	$ 0.049	$ 0.051	$ 0.055	$ 0.058	$ 0.055	$ 0.051	32%	22%
Large SPS Low Load Factor Flat Usage	$ 0.062	$ 0.067	$ 0.073	$ 0.076	$ 0.082	$ 0.086	$ 0.090	$ 0.085	45%	38%
Large SPS High Load Factor Flat Usage	$ 0.042	$ 0.045	$ 0.049	$ 0.051	$ 0.055	$ 0.058	$ 0.060	$ 0.055	43%	33%
Small LPS Low Load Factor Winter Peak	$ 0.057	$ 0.062	$ 0.069	$ 0.072	$ 0.077	$ 0.081	$ 0.081	$ 0.081	42%	42%
Small LPS High Load Factor Winter Peak	$ 0.022	$ 0.023	$ 0.026	$ 0.028	$ 0.030	$ 0.031	$ 0.031	$ 0.029	43%	32%
Small LPS Low Load Factor Flat Usage	$ 0.059	$ 0.063	$ 0.071	$ 0.075	$ 0.080	$ 0.084	$ 0.084	$ 0.083	42%	42%
Small LPS High Load Factor Flat Usage	$ 0.022	$ 0.024	$ 0.027	$ 0.028	$ 0.030	$ 0.031	$ 0.031	$ 0.029	43%	32%
Large LPS Low Load Factor Winter Peak	$ 0.057	$ 0.061	$ 0.069	$ 0.072	$ 0.077	$ 0.081	$ 0.081	$ 0.081	42%	42%
Large LPS High Load Factor Winter Peak	$ 0.022	$ 0.023	$ 0.026	$ 0.027	$ 0.029	$ 0.031	$ 0.031	$ 0.028	43%	32%
Large LPS Low Load Factor Flat Usage	$ 0.059	$ 0.063	$ 0.071	$ 0.074	$ 0.079	$ 0.083	$ 0.083	$ 0.083	42%	42%
Large LPS High Load Factor Flat Usage	$ 0.022	$ 0.024	$ 0.026	$ 0.028	$ 0.030	$ 0.031	$ 0.031	$ 0.029	43%	32%

Q. What immediate conclusions can one draw from this information?

A. Across the LGS, SPS, and LPS classes, customers have experienced increases in the range of 22%-45%, with a simple average increase across all profiles in those classes of 34% with the incorporation of the Temporary Tax Rider. Across the Residential and SGS classes, customers have experienced increases in the range of 38%-56%, with a simple average increase across all profiles in those classes of 42% with the incorporation of the Temporary Tax Rider.

Q. Is it fair to say that residential customers have experienced a 56% increase while LPS customers have experienced a 22% increase?

A. No. The Customer Profiles and experienced average $/kWh provided above are illustrative of the variation that occurs in bills among Ameren Missouri's customers. Given the changes in revenue responsibility and rate design that have occurred since 2007, and given the abilities of non-Residential customers to participate in rate switching, it is misleading at best to assert that any particular customer has experienced any given bill impact without simply comparing that customer's bill from 2007 with the same determinants as billed today (or vice versa).

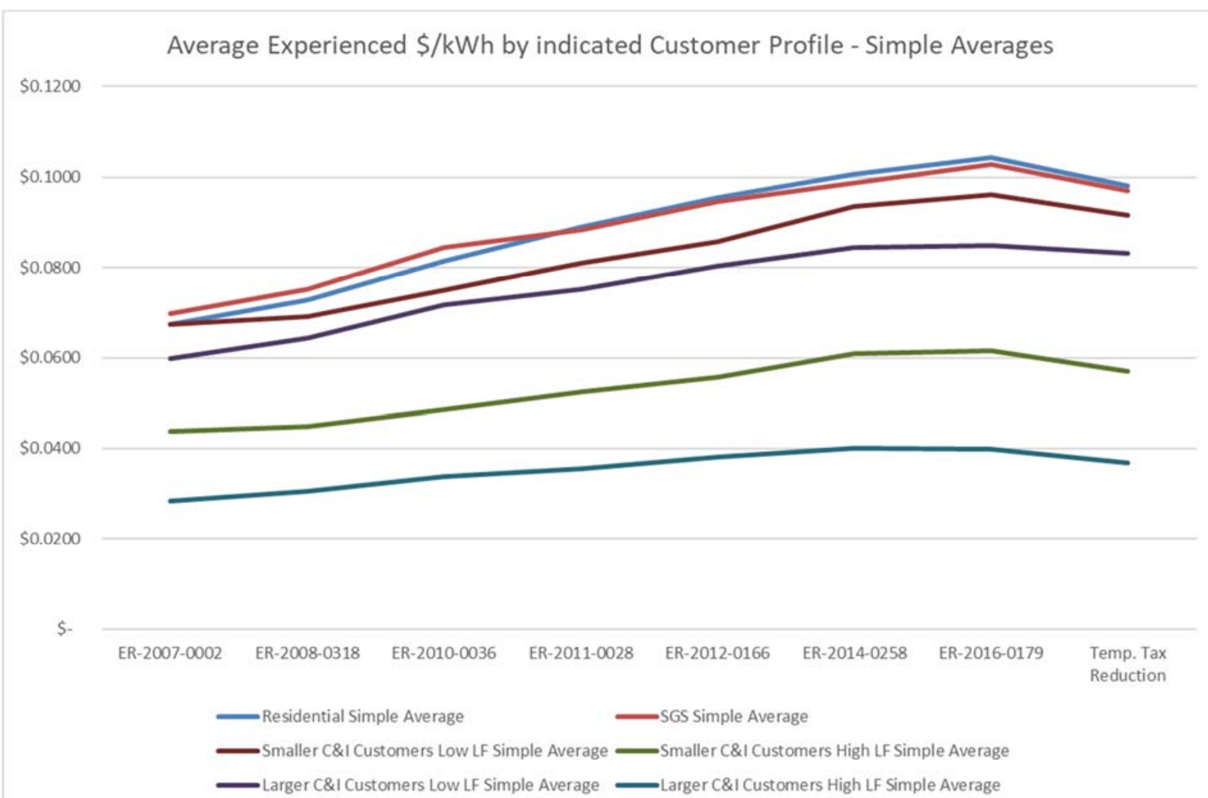
Q. What additional conclusions can one draw from this information?

A. Across the LGS, SPS, and LPS classes, lower load factor customers have consistently experienced greater increases than higher load factor customers. For facilitation of comparison, Staff found the simple averages of experienced average $/kWh for the Customer Profiles by (1) rate schedule, (2) by load factor for the LGS, SPS, and LPS classes combined, (3) by relative size within class for the LGS, SPS, and LPS classes combined, and (4) by relative size across classes, and by load factor across the LGS, SPS, and LPS classes. These results are provided in the table below:

continued on next page

	2007 Average $/kWh	2017 Average $/kWh	2019 Average $/kWh		
Residential Simple Average	$ 0.0673	$ 0.1043	$ 0.0981	55%	46%
SGS Simple Average	$ 0.0697	$ 0.1028	$ 0.0970	47%	39%
LGS Simple Average	$ 0.0553	$ 0.0790	$ 0.0743	43%	35%
SPS Simple Average	$ 0.0543	$ 0.0761	$ 0.0717	40%	32%
LPS Simple Average	$ 0.0398	$ 0.0568	$ 0.0554	43%	39%
Low Load Factor C&I Customer Simple Average	$ 0.0636	$ 0.0905	$ 0.0874	42%	37%
High Load Factor C&I Customer Simple Average	$ 0.0361	$ 0.0507	$ 0.0469	41%	30%
Smaller within Class C&I Customers Simple Average	$ 0.0504	$ 0.0715	$ 0.0680	42%	35%
Larger within Class C&I Customers Simple Average	$ 0.0492	$ 0.0697	$ 0.0663	42%	35%
Smaller C&I Customers Low LF Simple Average	$ 0.0673	$ 0.0962	$ 0.0916	43%	36%
Smaller C&I Customers High LF Simple Average	$ 0.0437	$ 0.0616	$ 0.0571	41%	31%
Larger C&I Customers Low LF Simple Average	$ 0.0598	$ 0.0849	$ 0.0831	42%	39%
Larger C&I Customers High LF Simple Average	$ 0.0284	$ 0.0399	$ 0.0368	41%	30%

The Residential and SGS simple averages are graphed below, with the LGS/SPS/LPS simple averages stratified by overall size and load factor:



Q. What immediate conclusions can one draw from this information?

A. The Larger C&I customers experienced lower average $/kWh throughout the study period. While the experienced average $/kWh associated with these customers is increasing (excepting the impacts of the Temporary Tax Reduction) it is at a lower rate than those experienced by the other profiles. Lower load factor C&I customers regardless of size are experiencing increases of magnitudes approaching that experienced by the SGS and Residential simple averages.[15]

Q. What is the result of dividing the total dollars of revenue from the LPS class as studied in Staff's direct revenue requirement calculation in this case by the total kWh for that rate schedule?

A. The resulting dollar per kWh value is $0.0571 for the total class. If the rates that took effect in July of 2007 are applied to the same customers at the same usage, the resulting dollar per kWh value for the total class is $0.0386. This is a change of 47.9%. These values do not reflect the Temporary Tax Rider.

Q. What is the experienced average $/kWh for the LPS class as studied in Staff's direct revenue requirement calculation in this case?

A. The lowest experienced average $/kWh for a single customer is $0.0513, and the highest is $0.0671. The simple average of all customers' experienced average $/kWh is $0.0576. These values do not reflect the Temporary Tax Rider. When the same customers' bills are calculated using 2007 rates, the lowest experienced average $/kWh for a single customer is $0.0347, and the highest is $0.0455. The simple average of all customers'

[15] The Customer Profiles and experienced average $/kWh provided above are illustrative of the variation that occurs in bills among Ameren Missouri's customers.

experienced average $/kWh is $0.0389. The change in simple averages is 48.0%, not including the impacts of the Temporary Tax Rider. It is important to consider that customers who choose to receive service on the LPS rate schedule today may have chosen to taken service on the SPS or LGS rate schedule in prior years – or vice versa – due to the changes in rate design that have occurred over time that may have encouraged rate switching.

Q. What changes to the LGS rate elements have occurred since Case No. ER-2007-0002?

A. The LGS rate structure with the rate of each element since July 2007 are provided below:

Large General Service	ER-2007-0002	ER-2008-0318	ER-2010-0036	ER-2011-0028	ER-2012-0166	ER-2014-0258	ER-2016-0179	Temp. Tax Reduction Effective Rate
Customer Charge	$ 66.79	$ 67.11	$ 72.26	$ 79.39	$ 83.04	$ 92.35	$ 94.51	$ 94.51
Low - Income Program Charge				$ 0.50	$ 0.50	$ 0.50	$ 0.56	$ 0.56
Summer Energy Charge								
Summer first 150 HU	$ 0.0751	$ 0.0751	$ 0.0809	$ 0.0889	$ 0.0930	$ 0.1034	$ 0.1058	$ 0.10118
Summer next 200 HU	$ 0.0565	$ 0.0566	$ 0.0609	$ 0.0669	$ 0.0700	$ 0.0778	$ 0.0796	$ 0.07498
Summer additional HU	$ 0.0380	$ 0.0380	$ 0.0410	$ 0.0450	$ 0.0470	$ 0.0523	$ 0.0535	$ 0.04888
Summer Demand Charge	$ 3.51	$ 3.51	$ 3.78	$ 4.15	$ 4.34	$ 4.83	$ 5.40	$ 5.40
Winter Energy Charge								
Winter first 150 HU	$ 0.0473	$ 0.0473	$ 0.0509	$ 0.0560	$ 0.0586	$ 0.0651	$ 0.0665	$ 0.06188
Winter next 200 HU	$ 0.0351	$ 0.0351	$ 0.0378	$ 0.0415	$ 0.0434	$ 0.0483	$ 0.0494	$ 0.04478
Winter additional HU	$ 0.0276	$ 0.0276	$ 0.0297	$ 0.0326	$ 0.0341	$ 0.0380	$ 0.0389	$ 0.03428
Seasonal Energy Charge	$ 0.0276	$ 0.0276	$ 0.0297	$ 0.0326	$ 0.0341	$ 0.0380	$ 0.0389	$ 0.03428
Winter Demand Charge	$ 1.30	$ 1.30	$ 1.40	$ 1.54	$ 1.61	$ 1.79	$ 2.00	$ 2.00

Q. What percentage change has occurred to each rate element?

A. The table below indicates the changes to the magnitude of each rate element since July of 2007 through the tariffed rates in effect today, with and without the impact of the Temporary Tax Rider applied to the energy charge blocks. It also provides the magnitude of each rate element proposed by the parties to this case that provided a rate design recommendation, and the percentage change from the 2007 magnitude.[16]

[16] The Ameren and MECG proposals are designed to recover the Ameren Missouri direct-requested revenue requirement.

Large General Service	ER-2007-0002	ER-2016-0179	Temp. Tax Reduction Effective Rate	Ameren Proposed	Staff Recommended	MECG Proposed	Without Tax Reduction	With Tax Reduction	Ameren Proposed	Staff Recommended	MECG Proposed
Customer Charge	$ 66.79	$ 94.51	$ 94.51	$ 94.58	$ 82.58	$ 94.58	42%	42%	42%	24%	42%
Low - Income Program Charge		$ 0.56	$ 0.56	$ 0.06	$ 0.56	$ 0.56	Introduced in 2011				
Summer Energy Charge											
Summer first 150 HU	$ 0.0751	$ 0.1058	$ 0.10118	$ 0.09950	$ 0.09595	$ 0.09860	41%	35%	32%	28%	31%
Summer next 200 HU	$ 0.0565	$ 0.0796	$ 0.07498	$ 0.07490	$ 0.07306	$ 0.07420	41%	33%	33%	29%	31%
Summer additional HU	$ 0.0380	$ 0.0535	$ 0.04888	$ 0.05030	$ 0.05025	$ 0.04980	41%	29%	32%	32%	31%
Summer Demand Charge	$ 3.51	$ 5.40	$ 5.40	$ 5.08	$ 4.72	$ 5.40	54%	54%	45%	34%	54%
Winter Energy Charge											
Winter first 150 HU	$ 0.0473	$ 0.0665	$ 0.06188	$ 0.06525	$ 0.06161	$ 0.06190	41%	31%	38%	30%	31%
Winter next 200 HU	$ 0.0351	$ 0.0494	$ 0.04478	$ 0.04650	$ 0.04667	$ 0.04600	41%	28%	32%	33%	31%
Winter additional HU	$ 0.0276	$ 0.0389	$ 0.03428	$ 0.03660	$ 0.03750	$ 0.03620	41%	24%	33%	36%	31%
Seasonal Energy Charge	$ 0.0276	$ 0.0389	$ 0.03428	$ 0.03660	$ 0.03750	$ 0.03620	41%	24%	33%	36%	31%
Winter Demand Charge	$ 1.30	$ 2.00	$ 2.00	$ 1.88	$ 1.75	$ 2.00	54%	54%	45%	35%	54%

Q. What is apparent from the changes depicted in this table?

A. The percentages in the Without Tax Reduction and With Tax Reduction columns indicate that LGS customers today are paying bills with demand charges that are 54% higher than they were in 2007, while energy charges have only increased approximately 41% without the Temporary Tax Reduction, and 24%-35% with the Temporary Tax Reduction.

Q. What are the customers' experienced average $/kWh under these rate designs, and how do they compare to historic experienced average $/kWh results?

A. These values are provided in the table below.

Large General Service	ER-2007-0002	ER-2016-0179	Temp. Tax Reduction Effective Rate	Ameren Proposed	Staff Recommended	MECG Proposed	Without Tax Reduction	With Tax Reduction	Ameren Proposed	Staff Recommended	MECG Proposed
Small LGS Low Load Factor Winter Peak	$ 0.0650	$ 0.0932	$ 0.0886	$ 0.0888	$ 0.0847	$ 0.0880	43%	36%	37%	30%	35%
Small LGS High Load Factor Winter Peak	$ 0.0440	$ 0.0626	$ 0.0580	$ 0.0591	$ 0.0580	$ 0.0585	42%	32%	34%	32%	33%
Small LGS Low Load Factor Flat Usage	$ 0.0678	$ 0.0972	$ 0.0926	$ 0.0929	$ 0.0882	$ 0.0917	43%	36%	37%	30%	35%
Small LGS High Load Factor Flat Usage	$ 0.0440	$ 0.0627	$ 0.0580	$ 0.0592	$ 0.0581	$ 0.0585	42%	32%	34%	32%	33%
Large LGS Low Load Factor Winter Peak	$ 0.0691	$ 0.0989	$ 0.0938	$ 0.0946	$ 0.0901	$ 0.0930	43%	36%	37%	30%	35%
Large LGS High Load Factor Winter Peak	$ 0.0434	$ 0.0617	$ 0.0570	$ 0.0582	$ 0.0572	$ 0.0575	42%	32%	34%	32%	33%
Large LGS Low Load Factor Flat Usage	$ 0.0654	$ 0.0938	$ 0.0892	$ 0.0895	$ 0.0853	$ 0.0883	43%	36%	37%	30%	35%
Large LGS High Load Factor Flat Usage	$ 0.0434	$ 0.0617	$ 0.0571	$ 0.0583	$ 0.0572	$ 0.0576	42%	32%	34%	32%	33%

Q. What are the rate design recommendations of MIEC and MECG?

A. MIEC recommends reductions to the energy charges of the LPS rate schedule. MECG recommends reductions to the energy charges of the LGS and SPS rate schedule. Both recommend these classes receive an above-average decrease to the currently tariffed rates.

Q. What rationale underlies these recommendations?

A. As it relates to establishing the revenue requirements for each class, at page 15 of Mr. Chriss's testimony, he states, "MECG recommends that the Commission allocate the additional revenue decrease using the following steps: 1) Start with the revenue allocation as proposed by the Company at the Company's proposed revenue requirement, with all customer classes receiving the proposed decrease; and 2) Allocate any additional decrease to SGS, LGS and SP, LPS, and Company Owned Lighting based on their ratio share of the revenue neutral shift required to bring all classes to cost of service." Relevant to this statement is that the proposed Ameren Missouri decrease is $800,000, and Mr. Chriss goes on to state that "Missouri Industrial Energy Consumers ("MIEC") has sponsored the testimony of Greg R. Meyer in this case in which Mr. Meyer recommends a reduction in revenue requirement for the Company of approximately $67.2 million. *See Direct Testimony of Greg R. Meyer, Table 1*. As shown in Exhibit SWC-5 and Table 5, the proposed allocation methodology, at a reduction of $67.2 million, provides for rate relief for all customer classes while using the revenue requirement reduction to provide approximately a 62 percent movement towards cost of service-based rates for LGS and SP as well as the LP and Company owned lighting classes."

Similarly, at page 3 Mr. Brubaker of MIEC states "Schedule MEB-COS-6 shows class revenue adjustments required to move toward, but not all the way to, equal rates of return before considering any overall rate change. Page 1 shows the adjustments required to move 25% toward cost of service, and page 2 shows the adjustments to move 50% toward cost of service. I recommend that the adjustment be within the range of 25% to 50%. 25% should be the minimum movement, but if the rate decrease is substantially more than what Ameren Missouri has requested, movement closer to 50% could be accomplished. Any overall change in revenue should be applied as an equal percent to the revenues of all classes after making the interclass adjustments."

Thus, both witnesses base their class revenue responsibility recommendations on the Ameren Missouri study, which is based on a total company cost of service of $2.62 billion. Both parties recommend that the Ameren Missouri total company cost of service be reduced to $2.55 billion due to removal of capital cost recovery and production-related depreciation expense. However, neither revise the study results to account for the reduction in allocatable costs, and both base their recommendations on percentages of dollar values by class without adjusting those dollar values for the overall reduction in cost of service. This recommendation to disproportionately provide rate reductions to the energy-related rates within high load factor classes is not consistent with the reality that removing these costs from the Ameren Missouri study disproportionately reduces the revenue responsibility of the Residential and SGS classes, and the demand-related rate elements within a rate schedule.

Q. Could you provide a simple example of the inconsistency in the MECG and MIEC recommendations?

A. Yes. In the example below Class A is allocated $10,000 of net rate base, and $500 of expense. At a 7.5% rate of return, Class A has a class revenue requirement of $1,250. Class A provides $1,000 in revenue, so Class A is undercontributing by $250, which is 25% of its class revenue requirement.

7.50%	Class A	Class B	Class C	Total Company
Net Rate Base	$ 10,000	$ 10,000	$ 12,500	$ 32,500
Return on Rate Base	$ 750	$ 750	$ 938	$ 2,438
Expenses	$ 500	$ 750	$ 500	$ 1,750
Total Cost of Service	$ 1,250	$ 1,500	$ 1,438	$ 4,188
Revenue	$ 1,000	$ 1,000	$ 1,000	$ 3,000
Shortfall ($)	$ 250	$ 500	$ 438	$ 1,188
Shortfall (%) of CoS	20.0%	33.3%	30.4%	28.4%

In the example below, we will hold all else constant, but reduce the rate of return to 6.5%. Now, the Class A Cost of service is reduced from $1,250 to $1,150, thus Class A's shortfall is reduced to $150, which is 13% of its class cost of service.

6.50%	Class A	Class B	Class C	Total Company
Net Rate Base	$ 10,000	$ 10,000	$ 12,500	$ 32,500
Return on Rate Base	$ 650	$ 650	$ 813	$ 2,113
Expenses	$ 500	$ 750	$ 500	$ 1,750
Total Cost of Service	$ 1,150	$ 1,400	$ 1,313	$ 3,863
Revenue	$ 1,000	$ 1,000	$ 1,000	$ 3,000
Shortfall ($)	$ 150	$ 400	$ 313	$ 863
Shortfall (%) of CoS	13.0%	28.6%	23.8%	22.3%

Class B is allocated the same $10,000 of ratebase as Class A, but is allocated more expense. Notice that Class B's overall revenue requirement was reduced by the same $100 as Class A, but $100 is a smaller percent of $1,150 (Class A's revenue requirement) than it is of $1,400 (Class B's revenue requirement). Thus, Class B's shortfall as a percent of its class cost of service was reduced only 4.8%, not 7%.

Class C is allocated more ratebase than the other classes, but is allocated the same expense as Class A. It experiences a bigger dollar value change in class cost of service than does Class A, but it is expressed as a smaller change in the percentage.

	Class A	Class B	Class C	Total Company
$ Change	$ 100.00	$ 100.00	$ 125.00	$ 325.00
% Change	7.0%	4.8%	6.6%	6.0%

Please note that for consistency with the Ameren Missouri CCOS approach Staff provides the "percent" results above as a percentage of class cost of service, not as a percentage of revenue.[17]

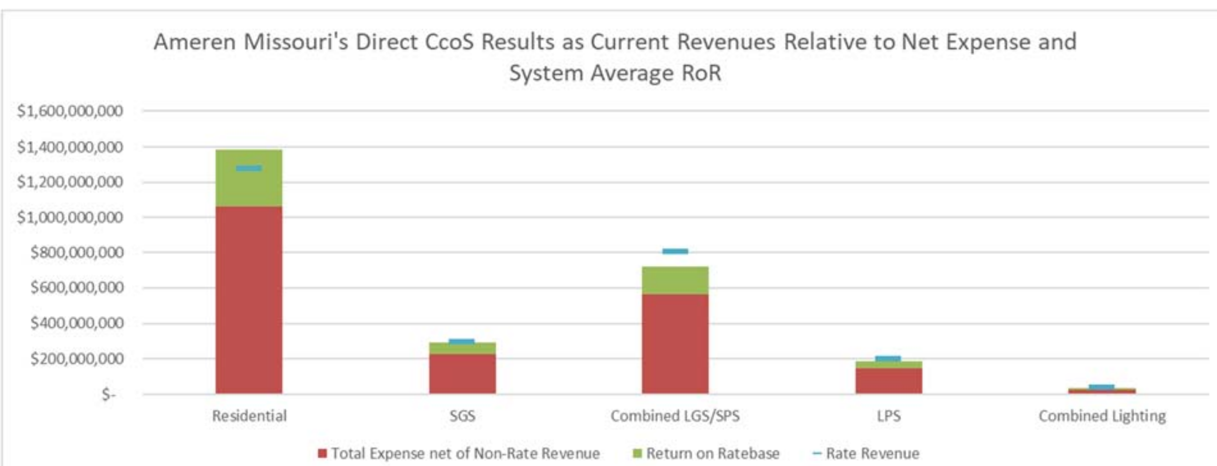
[17] Ameren Missouri chose to present the results of its CCOS as a percentage of Revenue Neutral Shift, which incorporates the allocations of other revenues to the classes, as opposed to a percentage change to rate revenue. While this is a reasonable convention for providing the revenue neutral shifts that would be required to exactly match the calculated cost of service under a study with each class providing an equal rate of return, it is not particularly helpful for studying what percentage changes would be applied to a class's rates (or revenue requirement) to exactly match the calculated cost of service under a study with each class providing an equal rate of return, and it places particular emphasis on the allocation of what have been sometimes referred to as "off system sales" revenues.

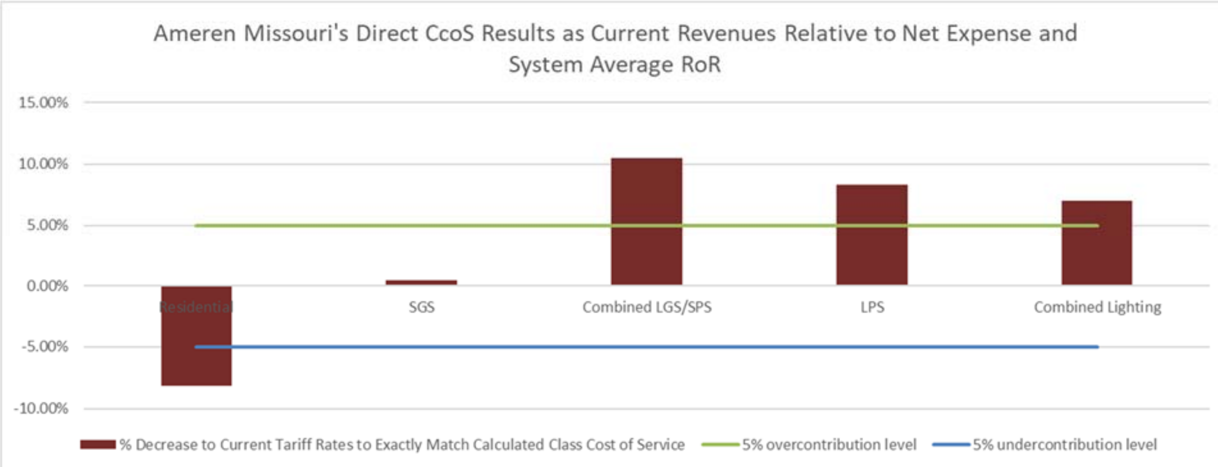
Q. What impact does incorporating the revenue requirement reductions, recommended by Mr. Meyer properly in Ameren Missouri's CCOS, have on the magnitude of the recommendations made by Mr. Brubaker and Mr. Chriss?

A. While neither conducted this exercise, Staff did review Ameren Missouri's CCOS to incorporate the two main adjustments recommended by Mr. Meyer.

Presenting the results in the same format as Staff's direct CCOS which provides the percent changes to class retail revenue to reverse any over or under contribution, the Ameren Missouri study results are provided below:

	Ameren Missouri's Direct CCoS Results				
	Residential	SGS	Combined LGS/SPS	LPS	Combined Lighting
Total Ratebase	$ 4,322,981,726	$ 909,690,166	$ 2,114,387,837	$ 508,200,892	$ 122,712,271
Total Expense net of Non-Rate Revenue	$ 1,064,573,505	$ 226,849,147	$ 565,879,945	$ 148,627,672	$ 27,242,056
Return on Ratebase	$ 318,128,225	$ 66,944,099	$ 155,597,801	$ 37,398,504	$ 9,030,396
Class Cost of Service at System Average RoR	$ 1,382,701,730	$ 293,793,246	$ 721,477,746	$ 186,026,176	$ 36,272,452
Rate Revenue	$ 1,278,256,444	$ 295,196,604	$ 805,845,703	$ 202,942,497	$ 38,998,824
Current Rate of Return	4.94%	7.51%	11.35%	10.69%	9.58%
Decrease to Current Tariff Rates to Exactly Match Calculated Class Cost of Service	**$ (104,445,286)**	**$ 1,403,358**	**$ 84,367,957**	**$ 16,916,321**	**$ 2,726,372**
% Decrease to Current Tariff Rates to Exactly Match Calculated Class Cost of Service	-8.17%	0.48%	10.47%	8.34%	6.99%



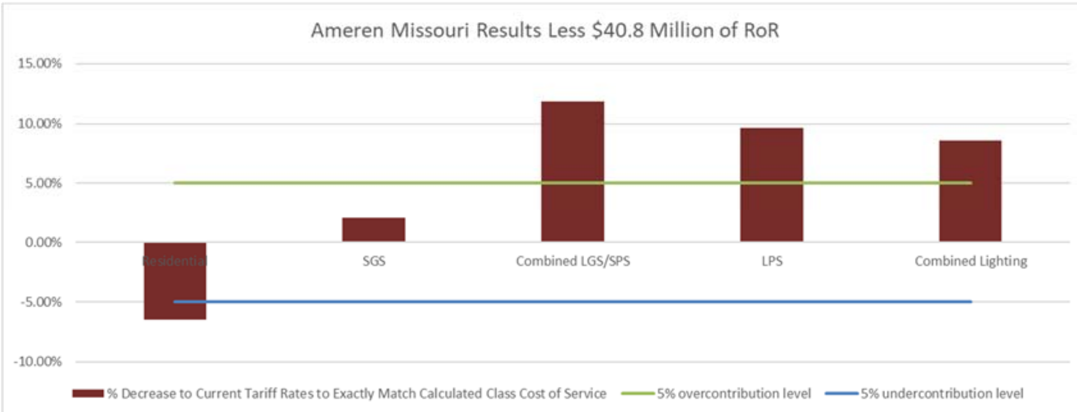


Q. Have you approximated the results of Ameren's CCOS that would follow from incorporating the Revenue Requirement recommendations made by MIEC and endorsed by MECG?

A. Yes. The first we will review is the impact of reducing Ameren Missouri's requested return on equity by $40.8 million,[18] pretax, to approximately $2.58 billion. The impact of this reduction, not including the reduction in income tax associated with the lower level of net income, is provided in the table below:

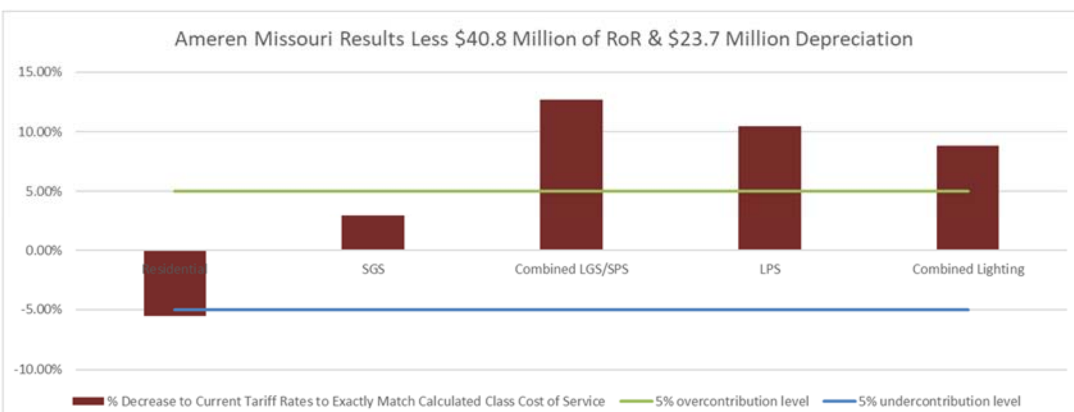
	Ameren Missouri Results Less $40.8 Million of RoR				
	Residential	SGS	Combined LGS/SPS	LPS	Combined Lighting
Total Ratebase	$ 4,322,981,726	$ 909,690,166	$ 2,114,387,837	$ 508,200,892	$ 122,712,271
Total Expense net of Non-Rate Revenue	$ 1,064,573,505	$ 226,849,147	$ 565,879,945	$ 148,627,672	$ 27,242,056
Return on Ratebase	$ 296,020,146	$ 62,291,870	$ 144,784,650	$ 34,799,523	$ 8,402,836
Class Cost of Service at System Average RoR	$ 1,360,593,651	$ 289,141,017	$ 710,664,596	$ 183,427,195	$ 35,644,892
Rate Revenue	$ 1,278,256,444	$ 295,196,604	$ 805,845,703	$ 202,942,497	$ 38,998,824
Current Rate of Return	4.94%	7.51%	11.35%	10.69%	9.58%
Decrease to Current Tariff Rates to Exactly Match Calculated Class Cost of Service	**$ (82,337,207)**	**$ 6,055,587**	**$ 95,181,107**	**$ 19,515,302**	**$ 3,353,932**
% Decrease to Current Tariff Rates to Exactly Match Calculated Class Cost of Service	-6.44%	2.05%	11.81%	9.62%	8.60%

18 See Greg R. Meyer, page 3.



Next, MIEC witness Brian C. Andrews proposes to reallocate, or redistribute, the Depreciation Reserve balance among the various Production Plant accounts. The impact of redistributing the Production Plant Depreciation Reserve balance is to reduce Ameren Missouri's proposed depreciation expense increase by $23.7 million.[19] The impact of this reduction is provided in the table below:

	Ameren Missouri Results Less $40.8 Million of RoR & $23.7 Million Depreciation				
	Residential	SGS	Combined LGS/SPS	LPS	Combined Lighting
Total Ratebase	$ 4,322,981,726	$ 909,690,166	$ 2,114,387,837	$ 508,200,892	$ 122,712,271
Total Expense net of Non-Rate Revenue	$ 1,052,683,215	$ 224,099,947	$ 558,715,435	$ 146,819,362	$ 27,151,996
Return on Ratebase	$ 296,020,146	$ 62,291,870	$ 144,784,650	$ 34,799,523	$ 8,402,836
Class Cost of Service at System Average RoR	$ 1,348,703,361	$ 286,391,817	$ 703,500,086	$ 181,618,885	$ 35,554,832
Rate Revenue	$ 1,278,256,444	$ 295,196,604	$ 805,845,703	$ 202,942,497	$ 38,998,824
Current Rate of Return	5.22%	7.82%	11.69%	11.04%	9.65%
Decrease to Current Tariff Rates to Exactly Match Calculated Class Cost of Service	**$ (70,446,917)**	**$ 8,804,787**	**$ 102,345,617**	**$ 21,323,612**	**$ 3,443,992**
% Decrease to Current Tariff Rates to Exactly Match Calculated Class Cost of Service	-5.51%	2.98%	12.70%	10.51%	8.83%



[19] Mr. Meyer discusses another $2.7 million in reductions to the Ameren Missouri revenue requirement associated with municipal levy taxes and management pay dates. Staff has not incorporated these adjustments into its tables above.

Q. In performing this exercise, how did Staff allocate the reduced depreciation expense?

A. Ameren Missouri's CCOS allocated the depreciation expense associated with production plant using the A&E 4NCP allocator calculated with Ameren Missouri's loads. In the above table, the reduced depreciation expense is calculated using the same allocator.

Q. If incorporated into Ameren Missouri's study, how are the revenue requirement reductions recommended by MIEC and endorsed be MECG properly allocated to the classes?

A. By subtracting the class cost of service results produced with the reduction included from the original class cost of service results, it is clear that approximately half of the recommended revenue requirement reduction is allocable to the Residential class if the MIEC/MECG recommended revenue requirement reductions are accurately allocated within the Ameren Missouri study:

	Residential	SGS	Combined LGS/SPS	LPS	Combined Lighting
Ameren Study Decrease to Current Tariff Revenues to Exactly Match Calculated Cost of Service	$ (104,445,286)	$ 1,403,358	$ 84,367,957	$ 16,916,321	$ 2,726,372
Revenues to Exactly Match Calculated Cost of Service, Incorporating $40.8 & $23.7 Reductions to Revenue Requirement	$ (70,446,917)	$ 8,804,787	$ 102,345,617	$ 21,323,612	$ 3,443,992
Allocation of $40.8 & $23.7 Revenue Requirement Reduction to Classes	$ 33,998,369	$ 7,401,429	$ 17,977,661	$ 4,407,291	$ 717,620

Q. After this simple exercise to incorporate MIEC's recommended reductions to total cost of service into the Ameren Missouri CCOS, what are the shifts that would follow from Mr. Brubaker's recommendation to apply a 25% - 50% removal of the "subsidy" associated with each class?

A. The revenue neutral changes that would follow, as well as the revenue requirement for each class, and the percentage change to rates within that class, are provided below, at both the 25% level and the 50% level of what Mr. Brubaker describes as movement towards the residential cost of service.

	Residential	SGS	Combined LGS/SPS	LPS	Combined Lighting
25% Residential Change	$ (17,611,729)	$ 1,140,890	$ 13,261,549	$ 2,763,031	$ 446,259
50% Residential Change	$ (35,223,458)	$ 2,281,781	$ 26,523,098	$ 5,526,062	$ 892,518
Final Revenues at 25%	$ 1,295,478,051	$ 293,965,620	$ 792,338,211	$ 200,117,528	$ 38,540,662
% Change at 25%	1.3%	-0.4%	-1.7%	-1.4%	-1.2%
Final Revenues at 50%	$ 1,313,089,780	$ 292,824,730	$ 779,076,662	$ 197,354,497	$ 38,094,403
% Change at 50%	2.7%	-0.8%	-3.3%	-2.8%	-2.3%

Q. Do the rate design recommendations of MECG reflect the cost-causation of the of the $67 million revenue reduction recommended by MECG?

A. No. Although the revenue requirement sought to be reduced is related to costs of capital and the return of capital associated with owning generating assets, Mr. Chriss advocates that the reduction in this case be disproportionately applied to energy charges.

Q. What are the costs of obtaining energy through the MISO Day Ahead market ("DA") to serve customers on each rate schedule, and are the DA energy costs the only costs that are caused strictly by the energy consumed by customers?

A. No. In a given day, there are expenses that would cease to be incurred by Ameren Missouri if no customer consumed energy. Those costs are DA energy, real time energy, ancillary services, and certain transmission charges. The table below provides the product of each class's hourly load and the Ameren UE nodal LMP used by Staff in the production model in this case. The revenue, Day Ahead energy cost, the DA percent of total revenue, and the DA dollar per kWh for each class are provided.

	Staff Revenue by Class	Day Ahead Energy Cost	DA % of Total $	DA $/kWh	Variable expenses approx $/kWh	Variable % of Total $
Residential	$ 1,350,037,103	$ 385,962,551	29%	$ 0.0278	$ 0.0309	30%
SGS	$ 313,604,714	$ 97,066,151	31%	$ 0.0277	$ 0.0308	32%
LGS	$ 592,746,798	$ 226,895,758	38%	$ 0.0272	$ 0.0303	40%
SPS	$ 245,542,342	$ 103,738,912	42%	$ 0.0266	$ 0.0298	45%
LPS	$ 213,414,108	$ 101,153,118	47%	$ 0.0264	$ 0.0295	52%
Combined Lighting	$ 40,705,791	$ 4,578,947	11%	$ 0.0235	$ 0.0266	12%

The energy-functionalized revenue requirement presented by Ameren Missouri and reproduced by MECG are net of energy revenues generated by Ameren Missouri's sales into the MISO IM.

Provided below are the average costs per kWh of energy to serve load, adjusted to the at-meter value for secondary and primary voltages, based on Staff's direct production model result of $904,991,372.

	kWh at Meter	Loss % per Ameren	kWh at Transmission	$/kWh at meter
kWh @ secondary	24,379,138,178	108.15%	26,367,011,870	$ 0.0286
kWh @ primary	7,447,940,524	104.89%	7,812,283,209	$ 0.0278

Q. What is the $/kWh that MECG asserts should be recovered by the energy charge?

A. Reviewing MECG's Ex SWC-7, MECG asserts that approximately $301 million dollars should be recovered through the LGS and SPS energy charges. Dividing by the class kWh used in Ex SWC-8 and SWC-9, this results in approximately $0.02547 per kWh, at meter. Adjusting this recovery per kWh to account for the need to purchase more kWh at the transmission voltage than are sold at meter due to line losses, this equates to $0.02344 per kWh for LGS customers, and $0.02428 per kWh for SPS customers. In contrast, the simple average $/kWh by month at transmission voltage for energy purchased in the MISO DA is provided below. Green shaded squares indicate months in which the LGS recovery would exceed the around-the-clock average cost of energy. Unshaded squares plus the green shaded squares indicated months in which the SPS recovery would exceed the around-the-clock cost of energy. Red shaded squares indicate months in which neither recovery would exceed the around-the-clock cost of energy.

	January	February	March	April	May	June	July	August	September	October	November	December
2019 Simple Average	$ 0.0280	$ 0.0244	$ 0.0277	$ 0.0256	$ 0.0250	$ 0.0227	$ 0.0258	$ 0.0232	$ 0.0245	$ 0.0214	$ 0.0252	$ 0.0193
2018 Simple Average	$ 0.0343	$ 0.0233	$ 0.0228	$ 0.0243	$ 0.0279	$ 0.0279	$ 0.0289	$ 0.0289	$ 0.0294	$ 0.0331	$ 0.0332	$ 0.0300
2017 Simple Average	$ 0.0274	$ 0.0225	$ 0.0252	$ 0.0262	$ 0.0255	$ 0.0263	$ 0.0291	$ 0.0262	$ 0.0274	$ 0.0254	$ 0.0254	$ 0.0239
3 Year Simple Average	$ 0.0301	$ 0.0235	$ 0.0254	$ 0.0256	$ 0.0264	$ 0.0259	$ 0.0282	$ 0.0264	$ 0.0274	$ 0.0269	$ 0.0281	$ 0.0245

However, in reviewing MECG's SWC-11, a "Cost of Service Energy Rate" of $0.03349/kWh is presented for LGS, and $0.02003/kWh for SPS. While after adjusting for losses this LGS rate would match the DA cost of energy (ignoring the other costs of obtaining energy listed above) this SPS rate would fail to recover the cost of obtaining around-the-clock energy in a single month of the last three years.[20]

Q. Are there other factors to keep in mind in reviewing Mr. Chriss's testimony on energy charges?

A. Yes. The functionalized costs Mr. Chriss relies on draw from the Ameren Missouri class cost of service study. Not only do the costs portrayed in Mr. Chriss's testimony exceed MECG's recommended cost of service by $67 million, but also the $67 million to be removed is disproportionately related to functionalized demand costs.

Q. Mr. Chriss recommends movement away from the hours use rate structure. What is unreasonable about the hours use rate structure?

A. The hours use rate structure was a reasonable way to scale declining energy charges to individual customers within a class prior to the advent of advanced metering. It is not inherently unreasonable, but it is no longer the best tool for the job. It is particularly poorly suited for customers who have significant usage in the spring and fall, and at nighttime. As a work around to this shortfall, "seasonal" aspects are available as are time of day discount and

[20] Use of around-the-clock average is consistent with the loads of a customer with a 100% load factor.

adder riders. The end result is a complex rate design that is not understandable to customers and that does not recover costs as equitably as a straightforward well-designed time variant rate.

A time-variant rate structure similar to the "Ultimate Saver" rate proposed by Ameren Missouri for the Residential Class would be a more reasonable rate structure for the SGS, LGS, SPS, and LPS classes.

Q. In a well-designed hours use rate, which functionalized costs should be associated with which rate elements?

A. The customer charge should recover the cost of customer service and metering. The billing demand is based on a customer's NCP, therefore it should recover distribution and local facilities costs. Under an embedded costs paradigm, the first and second block of the energy charge should cover the cost of the related energy as well as the costs of generation, transmission, and distribution functionalized to capacity and energy, and the tail and seasonal blocks should cover the costs of generation, transmission, and distribution functionalized to energy.

Q. Mr. Brubaker testifies that Ameren-owned wind in future cases will disproportionately increase the residential revenue requirement. Is this prognostication reasonable?

A. No. Ameren Missouri represents that the planned wind build out is driven by its intended means of compliance with the Missouri Renewable Energy Standard (RES), and not as additional or replacement capacity for purposes of resource adequacy. The annual requirements under the RES are related to a utility's energy sales, not its capacity requirements. It is more reasonable to anticipate that future wind generation will be allocated on energy than it is to assume it will be allocated based on class capacity requirements.

Q. Are there other issues with the Ameren Missouri CCOS, which are also the basis of the recommendations of MIEC and MECG?

A. Yes. The "off-system sales" and the classification of the distribution system are not treated as reasonably as is possible in the context of the embedded cost study.

Q. Is allocation of "off-system sales" on the basis of energy - as was done in the Ameren Missouri study - reasonable in a study where production capacity costs and expenses are allocated using class demands?

A. No. Mixing and matching these allocations is not reasonable. As discussed in Staff's direct CCOS Report, in the sections "Summary of Bundled and Functionalized Cost Categories," and "Production and Transmission Related Costs - Assigned Capacity Study," the historic approach of netting Ameren Missouri's cost of obtaining energy to serve its load with the net revenues of sales of energy into the market assumed not to serve Ameren Missouri load has outlived its usefulness. Nonetheless, it is not logically consistent – even under this antiquated approach – to assume that the Residential and SGS classes should pay disproportionately for plants while the LGS, SPS, and LPS classes should disproportionately receive the revenues produced by the availability of those plants.

For example, Mr. Wills asserts that "customers with high load factors, which tend to use the system more efficiently and therefore cause less idle capacity, tend to pay lower realized per unit rates than customers with low load factors. Similarly, very low load factor customers, which cause significant idle capacity even on the very local infrastructure used to serve them (i.e. service lines and transformers, etc.), pay higher realized rates than high load factor users."[21]

[21] Wills page 22.

This "idle capacity" at generating plants is what enables off-system sales margins, if one is inclined to approach ratemaking using that construct.

Q. What is the underlying premise of Ameren's Minimum Distribution Study, using the pole account as an example?

A. Ameren Missouri's study is based on the premise that 40' poles are the shortest and cheapest poles Ameren Missouri routinely installs.

Q. Is this characterization consistent with the data provided by Ameren Missouri?

A. No. Provided below are the net counts and average cost of poles showing activity in 2017 and 2018 combined, 2018 only:[22]

2017 & 2018	Number	Total Cost	$/Pole
POLE,WOOD,30'	775	$ 1,328,495.88	$ 1,714
POLE,WOOD,35'	1,930	$ 5,506,343.79	$ 2,853
POLE,WOOD,40'	8,535	$ 31,314,508.97	$ 3,669
POLE,WOOD,45'	2,655	$ 9,201,347.08	$ 3,466
POLE,WOOD,50'	464	$ 2,006,156.12	$ 4,324
POLE,WOOD,55'	241	$ 1,228,398.19	$ 5,097
POLE,WOOD,60'	162	$ 1,185,913.43	$ 7,320
POLE,WOOD,65'	196	$ 2,729,825.93	$ 13,928
POLE,WOOD,70'	159	$ 1,690,587.88	$ 10,633
POLE,WOOD,75'	72	$ 1,109,930.14	$ 15,416
POLE,WOOD,80'	25	$ 400,161.94	$ 16,006

2018	Number	Total Cost	$/Pole
POLE,WOOD,30'	292	$ 387,074.30	$ 1,326
POLE,WOOD,35'	843	$ 2,329,163.26	$ 2,763
POLE,WOOD,40'	3,610	$ 13,988,433.15	$ 3,875
POLE,WOOD,45'	1,103	$ 3,893,635.87	$ 3,530
POLE,WOOD,50'	163	$ 818,454.38	$ 5,021
POLE,WOOD,55'	58	$ 256,143.45	$ 4,416
POLE,WOOD,60'	73	$ 332,957.57	$ 4,561
POLE,WOOD,65'	46	$ 533,255.36	$ 11,593
POLE,WOOD,70'	66	$ 518,897.11	$ 7,862
POLE,WOOD,75'	28	$ 357,101.37	$ 12,754
POLE,WOOD,80'	9	$ 160,045.66	$ 17,783

[22] Poles clearly outside of the range of possible relevance due to size or number of installations are excluded from these tables.

Finally, the counts of poles installed (the above figures reflect net installation/removal activity) in 2018 are provided below:

2018 Install Only	Count	Total Cost	Average $/Install
POLE,WOOD,30'	283	$ 390,911	$ 1,381
POLE,WOOD,35'	843	$ 2,329,163	$ 2,763
POLE,WOOD,40'	3,514	$ 14,050,063	$ 3,998
POLE,WOOD,45'	1,030	$ 3,911,327	$ 3,797
POLE,WOOD,50'	163	$ 818,454	$ 5,021
POLE,WOOD,52'	1	$ 102,687	$ 102,687
POLE,WOOD,55'	55	$ 263,618	$ 4,793
POLE,WOOD,60'	65	$ 343,592	$ 5,286
POLE,WOOD,65'	44	$ 544,104	$ 12,366
POLE,WOOD,70'	60	$ 524,262	$ 8,738
POLE,WOOD,75'	27	$ 370,415	$ 13,719
POLE,WOOD,80'	9	$ 161,512	$ 17,946

While many 40' poles were installed, it is clear from this data that other poles that are shorter and cheaper were installed in substantial quantities.

Q. How did Ameren Missouri create subaccount balances using the minimum system results?

A. Generally, Ameren Missouri relied on the Vandas study results from several years ago to associate the percentage of each distribution account to a voltage level. In this case, Ameren Missouri first assigned the "customer" portion determined using its minimum system study, then allocated the remaining plant balance using the Vandas study.

Q. Is this a reasonable approach?

A. This approach assumes that within a given distribution account, the "customer" portion is the same percentage of each of the remaining classifications of the distribution system: the HV distribution system, primary distribution system, and secondary distribution system. Using the poles account as an example, it does not seem reasonable to assume that as many 40' poles are used in the HV and primary distribution systems as in the secondary distribution system. It would be more reasonable to assume that a significant number of these poles are part of the secondary distribution system - if they truly are the "minimum" size pole installed. The more reasonable treatment would be to determine a "customer" portion at each voltage level. Ameren Missouri was unable to provide the information necessary to make such determinations. This lack of data would be addressed if record keeping measures discussed above are implemented.

OTHER TARIFF ISSUES

Q. Does Staff support or oppose the Ameren Missouri tariff revision to automatically move SGS customers exceeding a 100kW NCP threshold to the LGS rate schedule if that customer has an AMI meter?

A. Staff does not oppose this revision, but Staff is concerned that customers may experience significant rate shock. While historically it would be somewhat unusual for a small unsophisticated customer to exceed 100kW this demand would not be at all unusual for a customer adding high speed EV charging capabilities. The fixed costs for a 100kW LGS customer are approximately $650/summer month and $300/winter month, as compared to $11.19 (single phase) and $21.38 (three phase) year round for an SGS customer, and the LGS first block rates that would apply to a customer with a low load factor are not significantly less than the SGS energy charges. Under the rate design proposals of MECG, MIEC, and Ameren Missouri, the demand charges and first block energy charges for the LGS class would remain largely at current levels.

Staff recommends that Ameren Missouri reach out to customers within 2-3 business days of a meter reading triggering this provision, notifying the customer of the change and educating the customer on the LGS rate schedule. Ameren Missouri should also inform such customers of the Optional Time-of-Day Adjustments available consistent with Rider I.

Q. Does Staff support Ameren Missouri's proposed addition to Rider I that "Customers with advanced metering installed will automatically have the provisions under Rider I applied without request?"

A. Staff supports what it understands as the concept, but language improvements are necessary as it is unclear whether the switch to Rider I is reversible at the option of the customer. Also, consistency across voltages and potential revisions of the Rider I (and related SPS and LPS) adjustment rates are necessary pending the final revenue requirement in this case. Staff is also concerned that the billing cycle timing issue as discussed above be addressed. Because SGS customers may prefer to move to the ToU rate option rather than standard SGS rates with the Rider I adjustment, customers should be informed of the options and make an affirmative selection between the two. Staff would also support applying this requirement to SPS and LPS customers.

Q. Ameren Missouri's filed tariff sheets remove the Large Transmission Service Rate Schedule, is this reasonable at this time?

A. Staff is unaware of any circumstances that would contradict removal of the LTS rate schedule at this time. In particular, the provisions of the tariff concerning transmission of energy by other entities were reflective of a contractual relationship between the specific former LTS customer and the physically related transmission service provider. If a new customer were to emerge as seeking service at the transmission voltage, it would be more appropriate to design any provisions for transmission service by others to reflect the situation as it may exist at that time and circumstance.

Q. Has Ameren Missouri presented evidence supporting a change to the LPS tariff requirements, or proposed what change it is contemplating?

A. No.

Q. You discuss several aspects of rate design, class cost of service, Ameren Missouri's proposals and other parties' Direct filings. Can you summarize your overall recommendations?

A. Staff does not recommend any overall shifts in class revenue responsibility at this time, and recommends that the rates that result from the process described in my Supplemental Direct testimony be implemented. Improved record keeping and data management on the part of Ameren Missouri is essential to the modernization of the Ameren Missouri rate structure, which is advocated by all parties testifying on the matter, with the exception of MIEC.

Q. Does this conclude your rebuttal testimony?

A. Yes.

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Decrease Its Revenues for Electric Service	)))	Case No. ER-2019-0335

AFFIDAVIT OF SARAH L.K. LANGE

STATE OF MISSOURI COUNTY OF COLE	)))	ss.

COMES NOW SARAH L.K. LANGE and on his oath declares that she is of sound mind and lawful age; that she contributed to the foregoing *Rebuttal Testimony of Sarah L.K. Lange*; and that the same is true and correct according to her best knowledge and belief.

Further the Affiant sayeth not.

Sarah L K Lange

SARAH L.K. LANGE

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 21st day of January, 2020.

Dianna L. Vaught

Notary Public

DIANNA L. VAUGHT
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: July 18, 2023
Commission Number: 15207377